UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

IN RE ALTA MESA RESOURCES, INC. SECURITIES LITIGATION	Case No. 4:19-cv-00957 Judge George C. Hanks, Jr.

APPENDIX TO DEFENDANTS' OPPOSITION TO CLASS PLAINTIFFS' MOTION TO EXCLUDE CERTAIN TESTIMONY BY DEFENDANTS' EXPERT EDWARD FETKOVICH

In accordance with Court Procedure 7(B)(3), Moving Defendants submit this Appendix in support of their Opposition to Class Plaintiffs' Motion to Exclude Certain Testimony by Defendants' Expert Edward Fetkovich, which is filed concurrently herewith. Moving Defendants rely on the following evidence to support their motion:

Ex.	Description
A.	Expert Report on Alta Mesa Resources' Development of its Stack Acreage by Edward James Fetkovich dated August 31, 2023
B.	Excerpts of the Deposition of Edward Fetkovich taken on November 1, 2023
C.	Excerpts of the Deposition of Miles Palke (Ryder Scott 30(b)(6)) taken on June 13, 2023
D.	Artificial Lift Quote dated October 24, 2018, Bates numbered AMR_SDTX01885701
E.	Excerpt of Spreadsheet dated February 26, 2019, Bates numbered Fetkovich_SDTX03264

F.	Oyewole, *Artificial Lift Selection Strategy to Maximize Unconventional Oil and Gas Assets Value*, SPE-181233-MS (2016) (Def. Ex. 92)
G.	Excerpts of the Deposition of Taylor J. Kirkland taken on November 15, 2023
H.	Excerpts of the Deposition of Harold E. McGowen III taken on November 13, 2023

Dated: January 19, 2024

Respectfully submitted,

By /s/ *J. Christian Word*

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CERTIFICATE OF SERVICE

I certify that on January 19, 2024, a true and correct copy of the foregoing document was filed with the Clerk of Court using the CM/ECF system, which will send electronic notification of such filing to all counsel of record.

/s/ J. Christian Word
J. Christian Word

EXHIBIT A

UNITED STATES DISTRICT COURT
SOUTHERN DIVISION OF TEXAS
HOUSTON DIVISION

IN RE ALTA MESA RESOURCES, INC. SECURITIES LITIGATION	
ALYESKA MASTER FUND, L.P., et al. Plaintiffs, v. ALTA MESA RESOURCES, INC., et al., Defendants.	No. 4:22-cv-1189 Judge George C. Hanks, Jr.
ORBIS GLOBAL EQUITY LE FUND (AUSTRALIA REGISTERED), et al., Plaintiffs, v. ALTA MESA RESOURCES, INC., et al., Defendants.	.

EXPERT REPORT ON:
<u>ALTA MESA RESOURCES' DEVELOPMENT OF ITS STACK ACREAGE</u>

CONFIDENTIAL – SUBJECT TO PROTECTIVE ORDER

Prepared by: Edward James Fetkovich

Eddie Fetkovich
Prepared for Latham and Watkins, LLP
August 31, 2023

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I. QUALIFICATIONS OF EDWARD JAMES FETKOVICH

I am a petroleum engineer and a former senior-level manager with over 34 years of experience in the upstream segment of the oil and natural gas industry that involves drilling and production. I am qualified to opine on the matters discussed below based on my education, technical background, and years of industry experience producing hydrocarbons from petroleum reservoirs around the world, including from low-permeability petroleum reservoirs like the "STACK" in Oklahoma. I have a Bachelor of Science degree in Mechanical Engineering with a Petroleum Option from Oklahoma State University. I am a member of the Society of Petroleum Engineers ("SPE").

During my 34 years of industry experience, I have worked in different engineering and management roles at Phillips Petroleum Company, ConocoPhillips, and Cimarex Energy Company (now Coterra Energy). My prior engineering roles have included: (i) reservoir engineering, which assesses the size, nature, and producibility of petroleum reserves in rock formations underground; and (ii) production engineering, which assesses the best methods for moving hydrocarbons to the surface and processing them for sale or disposal. Among many prior management roles, I previously led Cimarex's development of the Woodford and STACK reservoirs in Oklahoma as Anadarko Exploration Manager. That work included leading a multi-disciplinary development team of land and legal professionals, geoscientists, and reservoir engineers. I also served as Cimarex's Director of Technology, leading a team of reservoir engineers and geoscientists, as well as teams for digital well and facility surveillance and geographical information system ("GIS") for all of Cimarex's operations. Relevant to this report, those assignments involved reserve forecasting, well-spacing evaluation, comparing fracture-stimulation design to well production results, and artificial lift recommendations.

Appendix A provides further information about my professional experience, including professional publications. My compensated rate is $500 per hour for my work on this case, including for the preparation of this report and any deposition or trial testimony. I have been assisted on this matter by others working under my direction. Neither my compensation, nor any compensation of those working under my direction, is in any way contingent upon my opinions in this report, the outcome of this lawsuit, or any other matter.

II. SUMMARY

A. Summary of Operational Opinions

I have been asked to review Alta Mesa Resources' and its predecessor company, Alta Mesa Holdings' (collectively, "Alta Mesa's") development of their acreage in the STACK play of Oklahoma,[1] and to express my expert opinion on whether the development was reasonable from an operational and technical perspective and consistent with industry practice. Following is a

[1] The "STACK" play gets its name from an oil field, a hydrocarbon-producing basin, and two counties in Oklahoma—namely, Sooner Trend (oil field), Anadarko (Basin), and Canadian and Kingfisher (counties).

summary of my opinions on those subjects, based on my in-depth analysis of Alta Mesa's development activities, and in light of my education, training, and experience in this field:

- The number and spacing of wells that Alta Mesa drilled in their STACK acreage was reasonable when considered in the context of: (i) the results of Alta Mesa's operations in the STACK in the 2014-2017 timeframe, including their well-spacing tests ("spacing pilots") during that period; (ii) standard industry practice during an operator's early development of its acreage; (iii) implementation of the 2018 development plan over the course of the year as Alta Mesa gained more knowledge from various development activities, including information from its multi-well tests ("well patterns") to determine efficient well counts and well spacing; and (iv) the opinions and activities of other STACK operators during this period.

  - When Alta Mesa planned their STACK development, the general view among STACK operators was that there were multiple strata ("benches") in the Mississippian formation that held hydrocarbons in commercial quantities, each of which could potentially be produced independently of the other benches without significant "well interference"—that is, without development of wells in one bench decreasing the productivity of wells in another bench. In light of the potential for production from multiple benches, and in line with other operators, Alta Mesa ramped up its drilling program beginning in May 2017 by drilling six new well patterns that tested well-counts and landing zones.

  - An important lesson from my experience in the STACK and other plays is that, once a unit is developed, it can neither be redrilled nor re-fracture-stimulated. For that reason, there is a general view in the industry that in early-phase development, before adequate data has been collected, it is better to slightly over-drill a prospect than under-drill it to ensure that reserves are not inadvertently left in the reservoir. This view was evident in what operators adjacent to Alta Mesa ("offset operators") were doing in the STACK during 2017-2018. During this time frame, offset operators showed a tendency to drill more wells per section than in later years.

  - Multi-acre development decisions cannot be made from the results of a single pattern. This point was particularly true for Alta Mesa's extensive STACK acreage. Multiple patterns need to be assessed before adjustments can be made, primarily because the implications of such assessments for capital expenditures and capital efficiency are significant. In Alta Mesa's case, the earliest date that the Company could begin to evaluate meaningful production information from the six multi-well patterns that it began drilling in May 2017 was June 2018. With that information and the continuous assessment of its operations, Alta Mesa acted reasonably to take additional steps—including the installation of ESPs in numerous wells—to understand the reasons for their wells' underperformance versus forecast and to adjust well counts and spacing accordingly.

- As discussed in detail below, Alta Mesa's opinion of the STACK's development potential and their activities in the STACK in 2017-2018 were in line with other STACK operators.

- Alta Mesa's use of ESPs was reasonable from an operational perspective and consistent with industry practice.

  - ESPs are well known in the industry to offer operators an effective method for evaluating and improving a well's performance. Alta Mesa's decision to deploy ESPs within their STACK acreage was a reasonable strategy for improving the productivity of the Company's wells and addressing operating issues such as "frac-hit" wells.

  - Alta Mesa began increasing its use of ESPs in May 2018. It installed ESPs between August 2017 and January 2019 on a long-term basis in 49 of its STACK wells (11% of total wells) and in 102 STACK wells in total (23% of all wells). The Company installed ESPs in three situations: (1) in new wells; (2) in existing wells to mitigate the effects of a "frac hit" from the fracture stimulation of nearby well(s); and (3) in existing wells to increase total production rates. My detailed review of the production plots from each of the ESP-installed wells shows that: (i) 20 ESPs (20% of total) were installed in new wells; (ii) 45 ESPs (44% of total) were installed to improve production, of which 76% produced a good to moderate response; and (iii) 37 ESPs (36% of total) were installed to mitigate the effects of frac hits, all of which (100%) produced a good response. These results demonstrate that Alta Mesa's use of ESPs was effective from a production standpoint and was reasonable under the circumstances.

  - Alta Mesa's use of ESPs was also in line with industry practice and other operators. According to a paper published in 2020 by the SPE: "In the present-day scenario, approximately 40% of the unconventional wells that are installed with [artificial lift] systems employ Gas Lift (GL), 36% resort to Electrical Submersible Pumps (ESPs), 13% employ Sucker Rod Pumps (SRPs), 7% use Plunger Lift (PL) while Jet Pumps (JETs) are employed in 4% of these wells."

- The use of deviated wellbores (which the Securities Plaintiffs[2] call "S-shaped wells"[3]) was common in Kingfisher County, where Alta Mesa drilled most of its STACK wells.

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[2] "Securities Plaintiffs" refers to the Plaintiffs in the following action: *In re Alta Mesa Securities Litigation,* 4:19-cv-00957 (S.D. Tex.)

[3] Although it is not entirely clear from their pleadings, Securities Plaintiffs appear to define "S-shaped" wellbore as a wellbore whose axis is inclined at an angle to vertical greater than 5 degrees per hundred feet of well tubing, and thus is said to have a "dog-leg severity" ("DLS") of

- My research revealed that, of 28 operators that drilled horizontal Mississippian wells in Kingfisher County between 2012 and 2021, 21 operators drilled wellbores having a DLS of greater than 5 degrees per 100 feet of depth. Thus, using the Securities Plaintiffs' definition of "S-shaped well," S-shaped wellbores were commonly used in the STACK.

- Alta Mesa drilled "S-shaped" wells, as the Securities Plaintiffs define the term, in 73 Mississippian wells, or 17% of total wells drilled. That percentage of total wells drilled is consistent with many of Alta Mesa's peers in the STACK, whose "S-shaped" wells drilled in Kingfisher County ranged between 4% and 33% of their total wells drilled.

- Although sources indicate that rod lift generally should not be used in wells having DLS exceeding 5 degrees, the ability to use rod lift technology on a well can be determined only by applying software modeling to that well. Other forms of artificial lift (such as gas lift and plunger lift) are available where a wellbore's deviation precludes use of rod lift. During many field visits for Cimarex between 2014 and 2021, I did not see rod lift being used in horizontal wells in the STACK. Cimarex did not use rod lift in their STACK wells.

B. Materials Considered in Forming the Opinions in this Report

Please see Appendix B and sources cited throughout this report.

III. OIL & GAS UPSTREAM OPERATIONS

A. General Background

Production of petroleum from any type of reservoir rock is predicated on the rock having two fundamental characteristics: porosity and permeability. Porosity refers to the void space between the grains of rock that allows the rock to store a medium. In our case, that medium is petroleum hydrocarbons in the form of oil, gas, and/or gas condensate.[4] It also includes formation water. The rock formation's porosity is interconnected, which allows the stored medium to move through the rock. Permeability refers to how freely the medium can move through the rock. The higher the permeability, the easier it becomes for the medium to move through the rock. Movement is generated by reducing the pressure that is exerted on the rock and the medium—*i.e.*, as pressure on the rock diminishes, mediums like petroleum hydrocarbons can more easily flow through void space within the rock. In these situations, the medium will move toward the point of

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greater than 5 degrees per hundred feet (or "5°/100 ft."). *In re Alta Mesa Sec. Litig.*, Third Amended Complaint, ECF No. 218 at 37.

[4] "Gas condensate" refers to hydrocarbons that are gaseous while in the reservoir, but condense to form a liquid as pressure is reduced. This occurs in two ways: (1) as gaseous hydrocarbons rise in the tubing toward the surface; and (2) as reservoir pressure depletes below the dew point pressure. The dew point pressure is the point in a gas condensate reservoir when droplets of liquid (condensate) first begin to condense from the gas.

least pressure. In the context of oil development, that point of least pressure is created at the wellbore when hydrocarbons (*i.e.*, the medium) begin flowing through the rock. Hence, porosity and permeability dovetail to produce flowing oil from a rock formation into a wellbore, after the pressure in the wellbore is reduced below the native pressure within the rock. As the medium is removed from the rock, the pressure within the rock is continually reduced.

In previous decades—before the development of unconventional, low-permeability reservoirs—higher-permeability rock was targeted and produced. Higher-permeability reservoirs could be drained by a single, vertically drilled well, or—depending on the areal extent of the reservoir—by multiple vertical wells.

By contrast, the STACK's permeability is low, which in turn requires drilling multiple horizontal wells in a drilling unit and employing hydraulic fracture-stimulation ("fracing" or "fracking") to release and recover the maximum economic reserves from the rock. Fracing of vertical wells does not provide adequate surface area within the STACK reservoirs to allow reserves to be produced economically. Instead, fracing of horizontal wells must be utilized.

1. Horizontal Wellbores

A horizontal wellbore is a hole drilled into the ground, either vertically or at multiple angles, and designed to eventually enter sub-surface rock horizontally to extract the hydrocarbons. Horizontal drilling creates a conduit for oil, gas, gas condensate, and/or associated water to flow from the rock to the surface for extraction. *See* **Figure 1**.

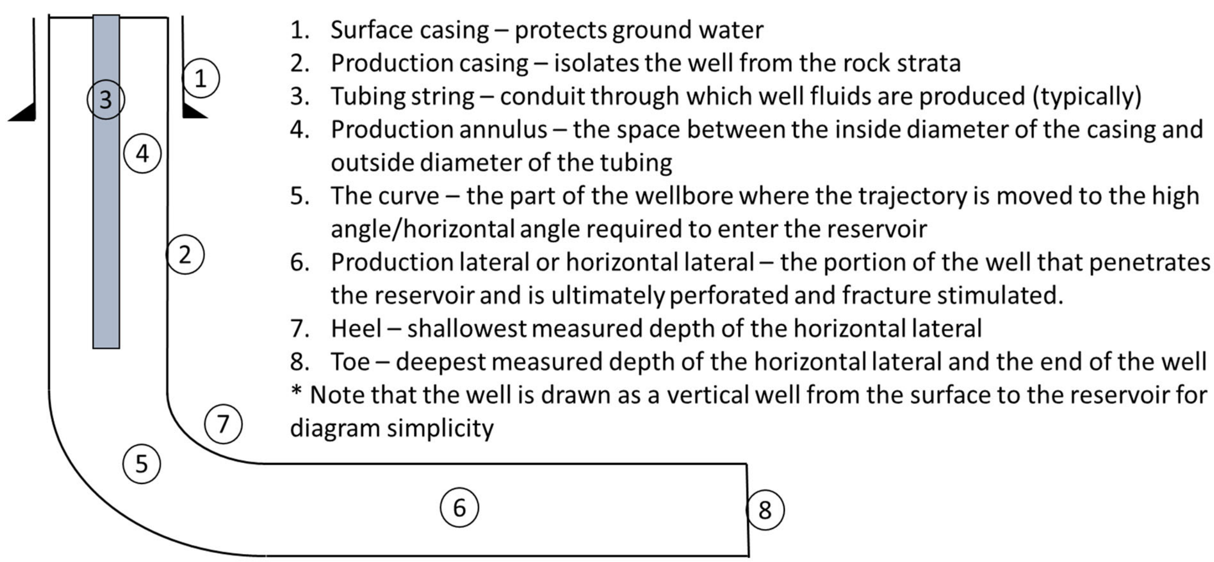

Figure 1 – Key Elements of a Horizontal Well

2. Fracture Stimulation

Horizontal wells drilled into low-permeability rock require fracture-stimulation to allow the hydrocarbons to flow out of the rock. The horizontal length of a well drilled into the reservoir is called a "lateral." While the mere drilling of a well may cause the release of some hydrocarbons, stimulation of the rock is necessary to produce commercially viable quantities of hydrocarbons. This is so because the pressure differential between the areas of rock exposed to lower pressure in the wellbore and the higher-pressure areas in the rock is not great enough (without stimulation) for the higher-pressure areas to drive out the hydrocarbons. Stimulation is applied to create numerous artificial fractures that are generally perpendicular, or at some angle, to the lateral. Fracture stimulation creates a significantly higher surface area against which the reservoir can flow, helping to drive out hydrocarbons into a wellbore.

To break rock sufficiently and create as much surface area as possible, the lateral is subdivided into "stages," and the stages are created starting from the farthest point of the lateral, called "the toe," to the nearest part of the lateral, called "the heel" (*see* **Figure 1**). In Alta Mesa's case, the stages were separated by external packers that isolated the lateral pipe to the rock formation. Each stage of the lateral included perforations that allowed the fracture stimulation fluids to exit the casing to break the rock and create fractures. *See* **Figure 2**. Each operator uses their own (generally proprietary) approach to the number of stages and methods to initiate fractures to stimulate a well effectively.

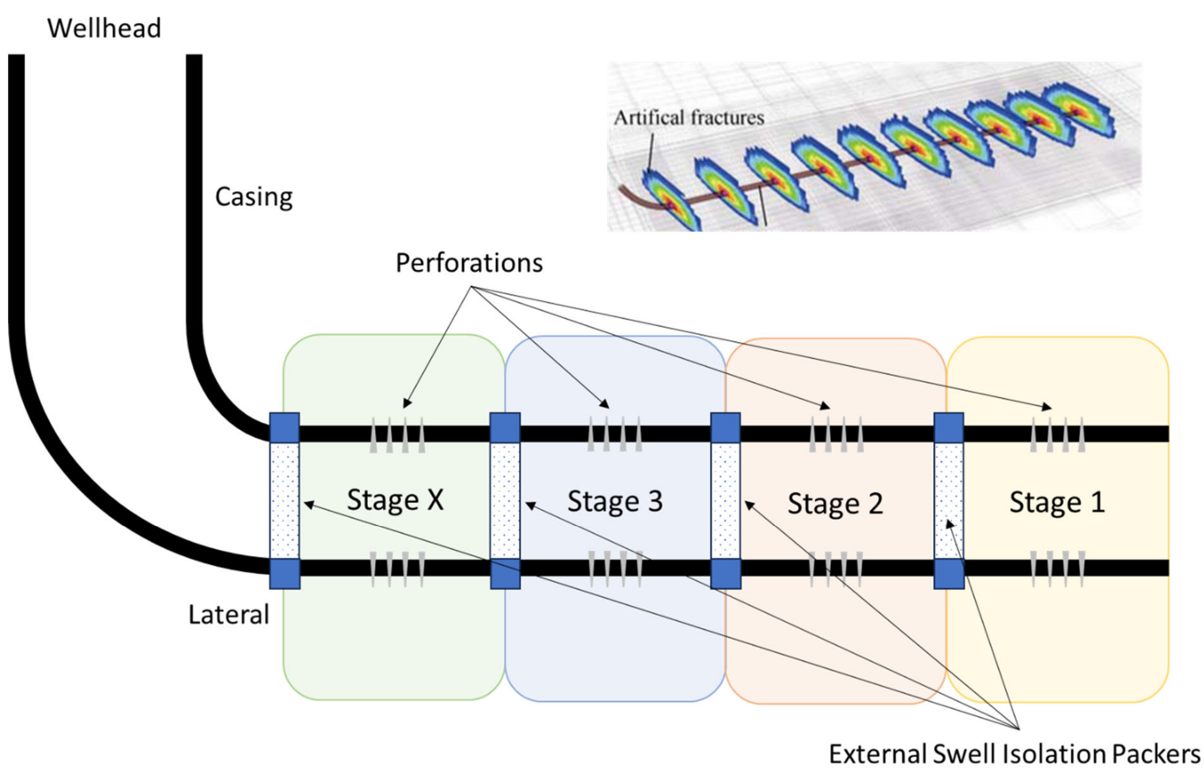

Figure 2 – Elements of a Fracture Stimulation

Fractures are created in a reservoir by pumping a fluid into the rock at a pressure that is higher than the reservoir pressure and necessary to "fail" (*i.e.*, break) the rock. Proppant—typically consisting of sand at a predetermined and consistent grain size—is placed in the fracing fluid; its purpose is to keep the fractures in the rock open after the fracing fluids are produced back through the well and the artificially-increased pressure (from the fracing) is released. The placed sand remains trapped as the pressure is released and the fractured planes close. These sand-packed fractured planes have much higher permeability than the native rock, creating additional pathways for the hydrocarbons (and any formation water) to move out of the rock, into the fractured planes, and finally into the wellbore where they flow to the surface.

Operators continuously adjust lateral stage length, perforations in the lateral, fracture fluid per foot, and/or mix of proppant per foot to achieve optimal economic results from a well. Due to the pace of drilling, a number of wells may be stimulated with a given fracture design before the operator can obtain production results sufficient to run an economic analysis of the production forecast against the overall cost of the stimulation. With the results from a number of wells, an operator can then draw broader conclusions and make adjustments, if necessary.

Because many fracture-stimulated wells are required to adequately drain an unconventional reservoir, capital costs are high. Many industry operators consider low-permeability drilling with horizontal wells to be comparable to mining or a manufacturing operation that makes the same repeatable widget. In this situation—and because of its repeatable nature—it is critical to minimize cost through scale (*e.g.*, drilling multiple wells from a single location and simultaneously stimulating multiple wells).

3. Well-Drilling in the STACK

Oklahoma land is subdivided into townships and ranges, with 36 sections within each township and range. Each section represents one square mile of land, and each section is owned by one or more mineral owners and surface owners, who are not necessarily the same individuals or entities.

After an operator secures a mineral lease from a landowner, a single horizontal well—called a "parent well"—is often drilled to establish production in paying quantities and to "hold" the lease prior to any deadlines specified within the lease. Once the operator believes they have sufficient information about the reservoir to determine how many wells are required to adequately drain it, additional wells—called "child wells"—are drilled. This is the typical development strategy. Sometimes, however, un-held acreage is developed with multiple wells drilled generally about the same time, and without a parent well. In that situation, the wells are called "sibling wells." Sibling wells are generally (but not always) drilled later in the acreage's development, once the productivity of the reservoir rock is better understood.

In the STACK, operators drill both one-mile (one section) wells and two-mile (two sections) wells. For this reason, the term "drilling unit" is often used to define a land/lease area, and the term can be used to mean either one or two sections.[5] The eastern side of the STACK—

[5] "Drilling unit" is sometimes referred to as a "drilling and spacing unit" or "DSU."

where Alta Mesa operated—was developed using one-mile wells. To the west, however, operators have used a mix of both one- and two-mile wells.

Wells in the STACK are drilled north to south, or vice versa, due to the generally east-west orientation of the natural (tectonic) stresses in the Mississippian rock. The natural stresses cause the fractures that are induced by the hydraulic fracing process to propagate away from (and generally perpendicular to) the wellbore at a high angle, as shown in **Figure 2**, above. This allows for the creation of a number of unique fracture planes along the horizontal wellbore, which improves hydrocarbon drainage.

In my experience in the STACK, a minimum of two surface locations (or drilling "pads") are required to fully develop a drilling unit. This is so because when a well reaches laterally (east or west) across an entire STACK drilling unit, operational problems arise due to the forces placed on the drill string as it rotates and bends from the surface to its downhole depth, which may involve drilling string lengths exceeding 15,000 feet. These forces are known as "torque" and "drag." Torque refers to the rotational or twisting force needed to rotate the drill pipe, and drag refers to the frictional force that must be overcome to push or pull the pipe in and out of the hole.

Wells in the STACK are typically drilled to the full legal length of the section to maximize reserve recovery. The wells' surface locations are placed along either the north or south section lines of the lease. That location minimizes wellbore length by allowing the "heel" of the well (*see* **Figure 3**) to be at approximately the same vertical position as the well's surface location, providing for the shortest wellbore length to achieve a full-length lateral in the reservoir.

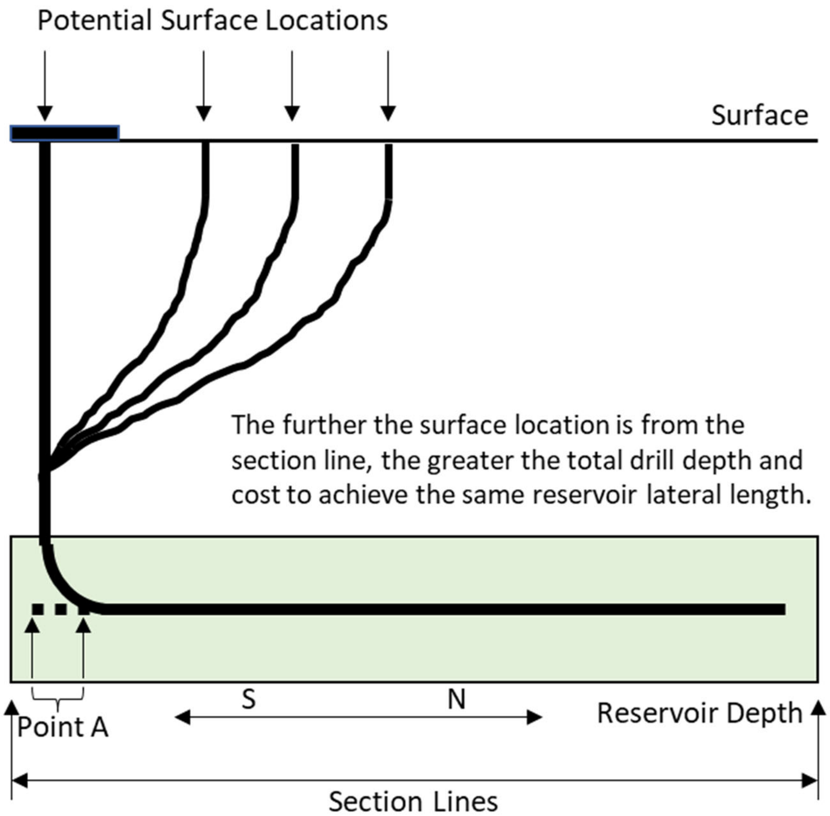

Figure 3 – Impact of Surface Location on Well Length

The land surface over the STACK is mostly rural, with some agriculture. Drilling pad locations are negotiated between operators and land owners. Land owners usually will seek to restrict the location and surface area used to keep operations away from homes or other structures. Similarly, land owners often will seek to avoid contacting agricultural equipment (*e.g.*, sprinkler systems), in turn minimizing any impairments on crop growth or other forms of land development.

B. Well Counts and Well Spacing

1. Overview

Decisions on acreage development require the combined expertise, experience, and judgment of a number of disciplines—geoscientists, reservoir engineers, drilling engineers, production engineers, landmen, and regulatory personnel. Those decisions are complicated by the fact that both the estimation of original oil in place and the amount of oil that can be recovered depend on the collection of large volumes of geological, geophysical, petrophysical, and engineering data, all of which are based on science but are uncertain in their accuracy. Thus, development decisions rely on a combination of uncertain data and the informed – but necessarily imperfect – judgment of scientists and engineers. This leads to a process that is inherently uncertain with no guarantee of commercial success. That is the nature of the upstream oil and gas business.

Reservoir engineers work with geologists to assess the potential volume of hydrocarbons in the rock, as well as the volume of hydrocarbons that should be able to be recovered from: (1) the overall area to be developed; and (2) each well. This recovery assessment is informed by:

1. *Fundamental physical calculations, including how much of the reservoir rock actually contains hydrocarbons and how much of those hydrocarbons can be mobilized*. At the well level, physical calculations are used to estimate the number of unique fracture planes in the rock that can be created to generate incremental pathways for the hydrocarbons to move from the reservoir. The calculations also consider how long those fracture planes will grow geometrically upward, downward, and outward from the wellbore. Outward propagation can lead to well-to-well interference, and impacts how closely situated wells can be placed. Other assumptions include: how much water and proppant are required to create an efficiently fractured and stimulated rock; how far apart the fracture-initiation points within the wellbore should be placed; and the best location for placement of the fluid and proppant pumped into each unique fracture plane, since dozens of unique fracture-initiation points are attempted within a single horizontal lateral (the goal of which is to create dozens of unique fracture planes).

2. *Well rates and reserve estimates using performance from existing parent wells.* Offset producing wells are evaluated to understand the productivity of the rock in terms of oil, gas, and water rate potential, and the trend of those rates is used to create forecasts. The forecasts lead to an estimate of oil and gas reserves, which when combined with the initial production rates and drilling and completion costs, allow for economic evaluation. This work helps the engineer to calibrate development assumptions.

3. *Investor presentations and scouting information from other nearby producers ("offsetting operators") in the play*. This information focuses on operators' wells drilled per section and estimated reserve recovery per well.

All of the above information is considered when creating a reservoir development plan. The plan consists of the overall available capital to be deployed, the number of wells to be drilled, an estimate of the predicted rate of hydrocarbon production over time from each well (*i.e.*, a forecast), and the estimated ultimate recovery ("EUR") for each well in each development area.

Prior to creating a recommended development plan, operators typically run multiple "cases" (*i.e.*, scenarios or "sensitivity analyses") showing the economic impacts from assumptions that change the reserves per well, wells per section, well development costs, and expected hydrocarbon prices. Once the development plan has been approved by an operator's senior management, drilling rigs and fracture stimulation crews are contracted.

2. Development Planning and Assessment

Commercial development of hydrocarbon reservoirs is an inherently dynamic and complex process, requiring that an operator continuously assess its approaches to development and consider strategic changes to the same. The only way to test the assumptions included in a development

plan is by drilling different sections or partial sections with different well counts—called "patterns"—and often with different fracture stimulation designs, and then measuring the production results from the use of those assumptions through economic evaluation. For example, projected cashflow from a hydrocarbon forecast will be compared to the actual cost to drill, to fracture stimulate, to equip the well to flow, to dispose of any produced water, and to operate the well, resulting in a determination of economic present value and rate of return for each well and each pattern. The reserve recovery and economic values of individual wells and patterns will be compared to predrill expectations to see if adjustments are needed. This assessment process requires many steps and, importantly, significant time to execute, as operators must wait for sufficient well data to be generated and analyzed to determine whether changes to the plan should be made.

When the wells are placed on production, there is a "clean-up period," usually at least 14-60 days, during which time the fluids used to frac the well will be produced back through the well prior to achieving significant hydrocarbon flow. Hydrocarbon production will typically increase over time until the oil rate peaks, after which it will begin to decline and continue declining rather rapidly before the decline rate decreases and becomes more consistent. Only after the decline rate has become more consistent can the operator begin to generate a reasonable production forecast and estimate of the well's EUR. The overall time from the clean-up period to the point where an operator has production information sufficient to make a reasonable forecast takes, in most cases, at least four to six months.

Once an operator gains confidence around a given well's and/or development area's forecast, the operator will assess whether the wells are meeting predrill expectations, which is usually measured against a predrill forecast called a "type curve forecast." If performance differs from the forecast, the operator will likely consider a variety of reasons that might cause such a difference, be it for better or worse (*e.g.*, fracture stimulation design, lift methods, well-to-well spacing within the reservoir, etc.). Different combinations of well-spacing and fracture designs are typically tested simultaneously across an operator's acreage to evaluate well performance from the various well development strategies. As further discussed below, a critical part of this performance assessment is the need to ensure that any artificial lift equipment installed in the well is effectively lowering the pressure in the wellbore to maximize flow from the reservoir.

After an operator has sufficient production and related data from each development area, they then can finally assess and compare their results to other development areas—both from their own wells and from offset operators' wells—to determine whether well count, well spacing, and/or fracture stimulation design should be changed. With management's concurrence, a new development plan can be prepared and implemented, and the cycle will continue as necessary until management believes it has the optimal development plan in place.

3. Operational Issues Affecting Cost and Lag Time from Drilling to Production

Low-permeability horizontal wells are expensive to drill, to complete, and to operate. These wells typically require several million dollars to implement (Alta Mesa's wells cost

approximately $3.5- to $3.9 million dollars per well).[6] Coupled with the fact that production rates will rapidly decline, operational planning is a particularly cost-sensitive aspect of oil and gas development.

The repetitive nature of drilling and completing multiple wells and then bringing them online creates cost-reduction opportunities. During my tenure at Cimarex, I observed first-hand that commercially viable land development is accomplished through carefully planned steps, including: (i) signing multi-well rig and multi-well fracture stimulation contracts with third-party vendors; and (ii) drilling multiple wells on a single drilling pad or surface location to reduce the time required for rig movement, fracture stimulation, and rig-up/rig-down ("mob" and "de-mob"). Time and costs can also be saved with multi-well surface pads by alternating the fracture stimulation of well segments between wells (*i.e.*, using "zipper fracs"), reducing the size and footprint of production facilities, and minimizing connections to points where the hydrocarbons will be delivered and sold.

While drilling and completing multiple wells from the same surface pad reduces cost, it also increases the time required from drilling to production due to the steps required to complete the process. Those steps, in order, are:

1. Drill all wells;

2. Take drilling rig down and move it off the drilling site;

3. Build production facilities;

4. Move the fracture-stimulation equipment to the drilling site. Sometimes there is a waiting period (from a day to a few months in my experience) before a fracture-stimulation crew becomes available;

5. Fracture stimulate the wells;

6. Take fracture-stimulation equipment down and move it off the drilling site;

7. Run tubing and artificial lift equipment and connect it to the production facility;

8. Initiate production. For safety reasons, first flow from wells must wait until all wells are stimulated and equipped to flow by running tubing and artificial lift equipment into the wellbore and then connecting the well to production facilities at the surface.

In my experience, a four-well pad could require four to five months from commencement of drilling ("spudding") the first well to first production from all four wells. To illustrate this time period, the following approximate times are used: 10 days to drill each well (a total of 40 days), 60 days to build the composite production facilities, seven days to fracture-stimulate each well (28 days), and five days to run tubing and install artificial lift in each well (20 days). There is variation in these numbers for each situation. Importantly, that time frame assumes efficient execution of

[6] *See* AMR_SDTX000003589.

all the steps listed above—from spudding to first production. The time required to complete all of these steps depends on the number of wells drilled and delays in equipment delivery and installation due to any number of reasons.

C. Artificial Lift

1. Background

Artificial-lift methods are used to reduce hydrostatic pressure on the reservoir—*i.e.*, the pressure exerted by the combined weight of the column of oil, water, and gas above the reservoir—thereby increasing the ability of the reservoir fluids to flow from the reservoir and into the wellbore as the reservoir's native pressure depletes. Application of artificial-lift technology is a critical component of maximizing reserve recovery from a reservoir.

2. Types of Artificial Lift Used in the STACK

Operators use some form of artificial lift on every hydrocarbon-producing well to assist in bringing the hydrocarbons to the surface. In horizontal wells drilled in the STACK, I am aware of the use of gas lift, electric submersible pump ("ESP"), jet pump, and plunger lift. Rod lift (also known as "beam lift") is used on a very limited basis in the STACK. During my time working in the STACK, I did not witness rod lift being used in horizontal wells there.

As demonstrated in **Figure 4**, a graphic taken from a May 14, 2018 presentation to Alta Mesa's investors, Alta Mesa was well aware of all of these forms of artificial lift and their suitability for use across the life cycle of a well.

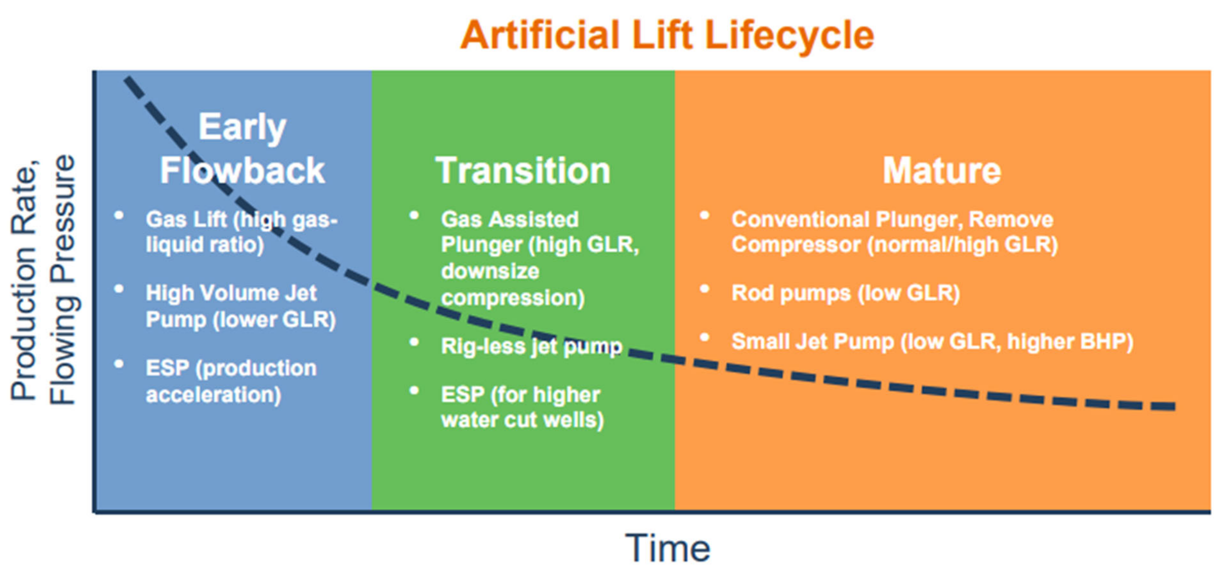

Figure 4 – Types of Artificial Lift Used Over a Well's Lifecyle[7]

A description of each form of artificial lift mentioned in **Figure 4** is provided in Appendix C.[8] Artificial lift adds energy in one form or another—*e.g.*, injecting high-pressure gas into the tubing for gas lift; using electricity to power a downhole motor and pump for ESP; operating a motor at the surface to move rods up and down to stroke a downhole pump for rod lift—to lower pressure in the wellbore and induce hydrocarbons to flow from the reservoir into the wellbore and then to the surface. Each method has its optimum range of applicability.[9] In my experience, gas lift is most frequently used from a well's early life through mid-life, while plunger lift is frequently used late in a well's life. ESPs are also useful in a well's early life, particularly when there is a question about whether poor well performance is due to insufficient lift, and to return a well to production after it has been hit by fracing of an offset well. Alta Mesa's use of ESPs was in line with **Figure 4**.

3. Factors Affecting Choice of Artificial Lift Type

Operators consider a variety of factors, including historical experience, when selecting a particular artificial lift method. Although those factors can be broken down into three primary categories (as listed below), operators generally consider the following factors when making an artificial lift selection.

Reservoir factors:

- Depth
- Pressure
- Porosity
- Fluid saturations
- Permeability (as discussed above, meaning a measure of the reservoir's ability to allow for gas, oil, and water to flow)
- Overall productivity of the stimulated rock

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[7] Alta Mesa Resources, "First Quarter 2018 Operational Update" at 9, May 14, 2018, http://altamesa.net/wp-content/uploads/2018/05/2018-AMR-first-quarter-operational-update.pdf. Alta Mesa's information reflected in **Figure 4** is consistent with my knowledge of the suitability of each type of artificial lift over a well's life cycle.

[8] In Appendix C, the term "abandonment bottom hole pressure" refers to the actual bottom hole pressure when the well ceases to produce and is considered to be fully depleted. As noted, some types of artificial lift can achieve lower abandonment bottom hole pressures than other types.

[9] When artificial-lift equipment is added to a well, it is installed either at the top of the wellbore's curve, point 5 of **Figure 1**, or very slightly into the curve. Installing the equipment deeper in the wellbore does not meaningfully improve performance through further reduction of hydrostatic head. However, a deeper installation does increase the equipment's risk of failing or becoming stuck and unable to be removed from the wellbore. My review of available wellbore data indicates that Alta Mesa set their ESPs in a favorable location within the wellbore—*i.e.*, at the top of the curve into the lateral, or down to a wellbore deviation of at most seven degrees of the curve. These depths were approximately 600 feet vertically above the true vertical depth of the lateral.

- Oil, gas, and water gravities and viscosities
- Temperature
- Producing gas to total liquid (oil + water) ratio or "GLR"; or "gas-oil ratio" or "GOR." These factors impact the density of the mixture in the wellbore column, and thus the hydrostatic pressure on the reservoir.

Wellbore factors:

- Wellbore deviation at multiple points to understand the true vertical and measured depth profile
- Inside-casing diameter
- Tubing inside diameter, weight, and strength

Surface factors:

- Number of tanks for oil and water storage
- Size of the oil, gas, and water separator to split the three phases (oil, gas, and water)
- Required operating pressure
- Availability of electricity to power some forms of lift (*e.g.*, ESPs)
- Availability of high-pressure gas for gas lift, or for a gas compressor to create the high-pressure-gas required for gas lift
- Line pressure of pipeline and its ability to deliver gas for gas lift
- Distance to any homes or habitable structures for noise considerations

Table 1 lists the well-life application, optimal GLR conditions, and suitability for use in deviated wells for each method of artificial lift.[10]

Table 1 – Artificial Lift Application

Artificial Lift Typical Application Table

Lift Type	Well Life Application	Best Application	Use in Deviated Wells
Gas Lift	Early to Mid	Moderate GLR's, moderate to high liquid rates	Yes
ESP	Early to Mid	Low GLRs, high liquid rates - wells hit by offset frac	Yes
Jet Pump	Early	Low to mid GLRs, moderate liquid rates	Yes
Plunger Lift	Mid to Late	Mid to High GLRs, moderate to low liquid rates	Yes
Rod Lift	Mid to Late	Mid to Low GLRs, moderate to low liquid rates	Generally No in STACK*
* Depends on well angle and tortuosity			

Table 2 summarizes the pros and cons for each type of artificial lift method.

[10] **Table 6** below shows that Alta Mesa utilized these forms of artificial lift.

Table 2 – Artificial Lift Characteristics[11]

Artificial Lift Typical Application Table

Lift Type	Pros	Cons	Solids Handling	Achieve Low Bottomhole Pressure
Gas Lift	Good with high liquid rate wells and/or wells producing sand	Requires a gas compressor or source of high pressure gas, cannot achieve low bottom hole pressures	Good	No
ESP	Good with high liquid rate wells, high water rate wells resulting from that well being hit by an offset frac, wells that have been hit by an offset frac with formation gas significantly reduced, can achieve low bottom hole pressures	Requires electricity, can be poor on wells with high solids production	Poor	Yes
Jet Pump	Good on wells with moderate to high liquid rates, wells that produce sand, early life temporary use before gas lift gas or electricity is available for gas lift or ESP	Can have higher maintenance costs and intermittant run time issues. Generally considered a shorter term lift method until a different form of lift is available or ready, e.g. gas compressor or electricity	Good	No
Plunger Lift	Moderate to low liquid rate wells, wells that produce sand or paraffin, can achieve low bottom hole pressures	Excludes wells producing at high water rates and a low gas-oil ratio	Good	Yes
Rod Lift	Good on moderate to low liquid rate wells, can achieve low bottom hole pressures	Cannot handle sand production.* Poor in deviated wells due to the rods moving inside the tubing that causes wear.	Poor	Yes

*I noted Securities Plaintiffs' claim that Alta Mesa's drilling of S-shaped welbores precludes use of rod lift. As noted here, however, rod lift presents difficulties when drilling in sandy rock like that found in the STACK.

D. Wellbore Shape in Unconventional Reservoirs

1. Deviated Wellbores and Cost Savings

Use of deviated wellbores—*i.e.*, a wellbore whose axis is inclined at an angle to the vertical direction—is a standard practice in the development of unconventional reservoirs like the STACK. Because multiple horizontal wells must be drilled to deplete a reservoir with low-permeability rock, the wells are drilled from as few surface locations as possible. Therefore, wellbores must be deviated to maximize reservoir penetration while maintaining an appropriate distance (*i.e.*, spacing) from other wellbores in the same area of the reservoir to minimize competitive drainage.

Using deviated wellbores to minimize the required number of surface locations for full drilling unit development allows for significant cost savings. These savings are realized from:

[11] *See* Sections IV.B and IV.C in this report regarding Alta Mesa's deployment of ESPs to address the production impacts of high liquid rates and hits from offset-well fracs.

- Reducing the surface area to be leased (reducing lease cost);
- Allowing wells to be drilled back-to-back, reducing cost by minimizing the movement of drilling and fracture-stimulation equipment;
- Reducing hook-up and transfer times when fracing the wells, and allowing for a "zipper" type of frac, which further reduces cost;[12]
- Reducing surface equipment; *e.g.*, fewer separators and oil and water storage vessels;
- Reducing piping required to connect all of the wells to production equipment; and
- Reducing connections to gas purchasers and for oil and water transport (piping or trucking).

2. Types of Deviated Wellbores

In my experience, two deviated-wellbore designs are used to drill unconventional reservoirs from the surface to the desired reservoir penetration point: "build and hold" and S-shaped.[13] *See* **Figure 5**.[14]

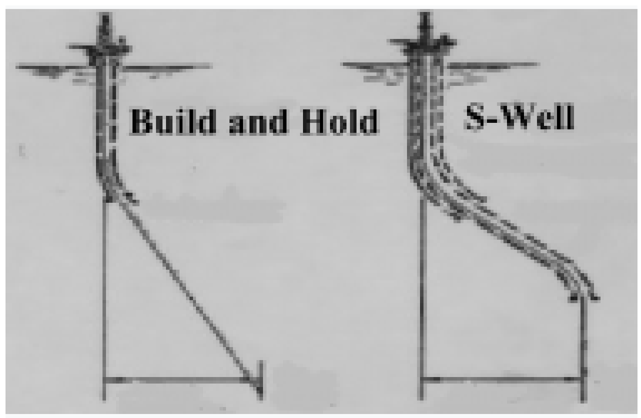

Figure 5 – Deviated Well Types

The **build and hold** form of wellbore design is used in the STACK when a well's surface location is near, and runs along, the north or south boundary of a lease. That location minimizes wellbore length by allowing the well's surface location to be situated approximately at the north or south location of the heel of the well, providing the simplest means for maximizing the lateral's exposure to reserves. In those locations, the surface pipe is set to a vertical depth of approximately 400–600 feet to protect ground water sources; below that depth, directional tools are used to change

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[12] The "zipper frac" technique alternates fracing between wells, allowing for one well to be frac'd while another is being perforated and set up for fracing. With zipper fracing, all wells will have their first stage frac'd, then all wells will have their second stage frac'd, and so on until all stages in all wells have been frac'd.

[13] As discussed below, a true "S-shaped wellbore" is not directly tied to a well's dogleg severity.

[14] *See* Society of Petroleum Engineers, https://petrowiki.spe.org/Directional_well_profile:_overburden_section (modified).

the inclination of the wellbore from vertical to the proper angle required to intersect the reservoir at the desired east/west location. *See* **Figure 6**. The "build" in the description refers to building the proper angle, while "hold" refers to holding that angle to the depth where the wellbore curves to penetrate the reservoir. The build and hold wellbore is the simplest deviated well design, but it typically leaves un-stimulated and un-produced a small part of the reservoir at the well's heel due to the wellbore's geometry turning from vertical or from inclined to horizontal. *See* Point A in **Figure 7**.

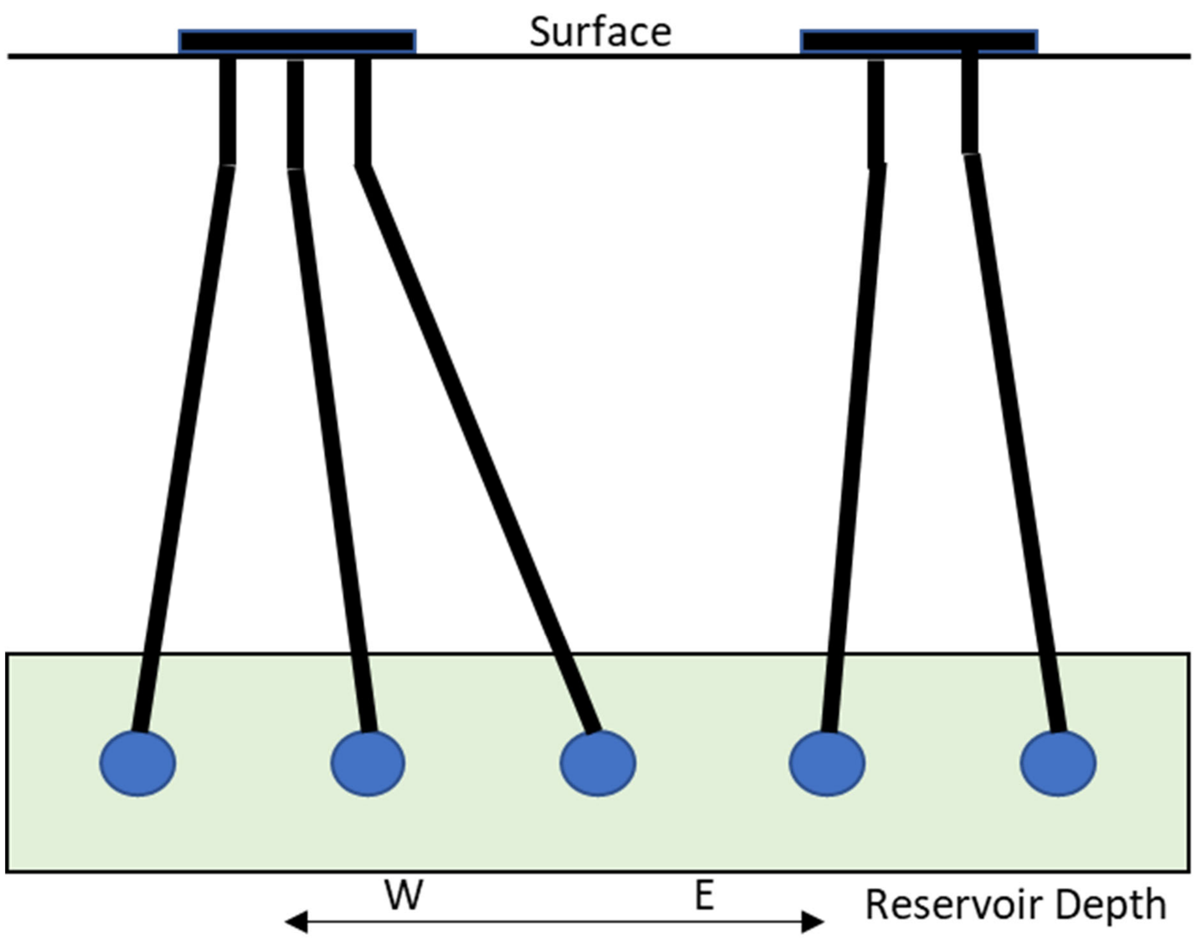

Figure 6 – Well Geometry Illustration

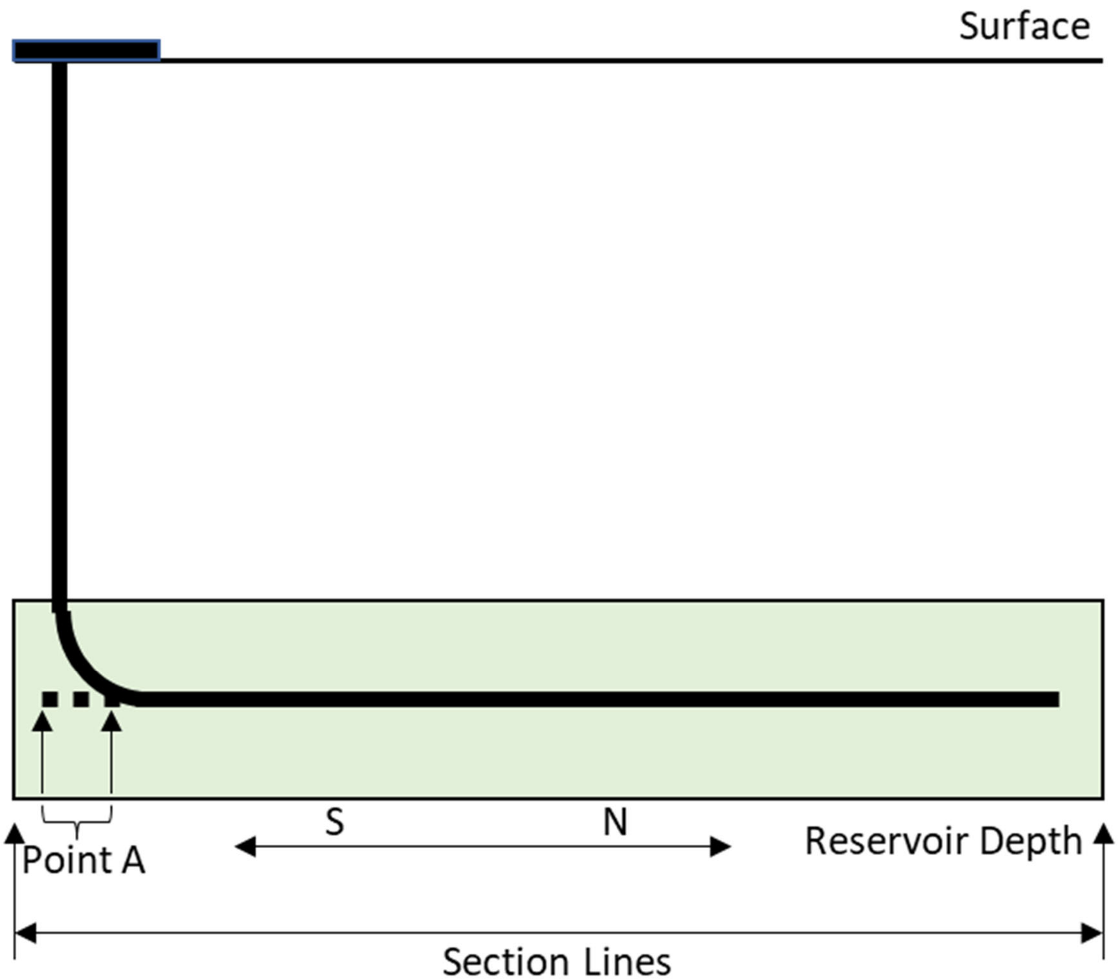

Figure 7 – Build and Hold Wellbore

An **S-shaped well**, in my experience, has the same east/west inclination as a build and hold well, but extends farther (*i.e.*, "kicks out") to either the north or south as compared to a build and hold well (*i.e.*, the S-shaped well-illustrated in **Figure 8** kicks south). The wellbore of an S-shaped well typically extends into an adjacent land section prior to turning horizontal and re-entering the section to be developed. This is represented by the dashed line in **Figure 8**. The solid line at the same depth as the dashed line represents the lateral of a build and hold wellbore design.

Note that an S-shaped wellbore *can* remain entirely within a section, as shown in **Figure 5**. My experience in the STACK, however, is that an "S-shaped well" refers to a well whose path extends beyond the section being developed before re-entering that section. That definition is supported by an Alta Mesa land map illustration, which shows the well path for several wells traversing out of the section being developed and into an adjacent section, before re-entering the section being developed. *See* **Figure 9**.

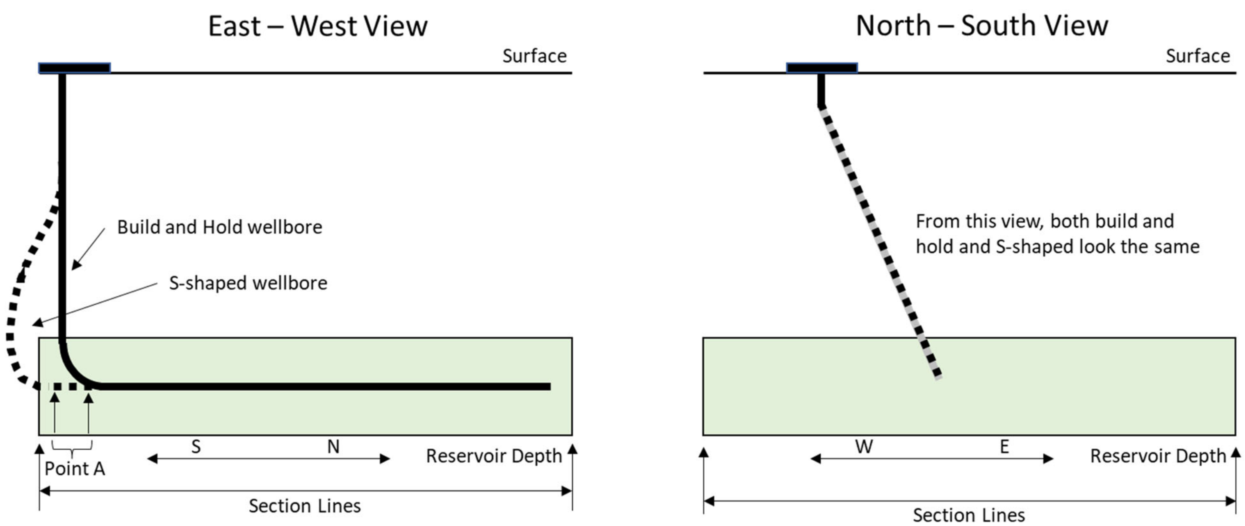

Figure 8 – S Shaped Wellbore

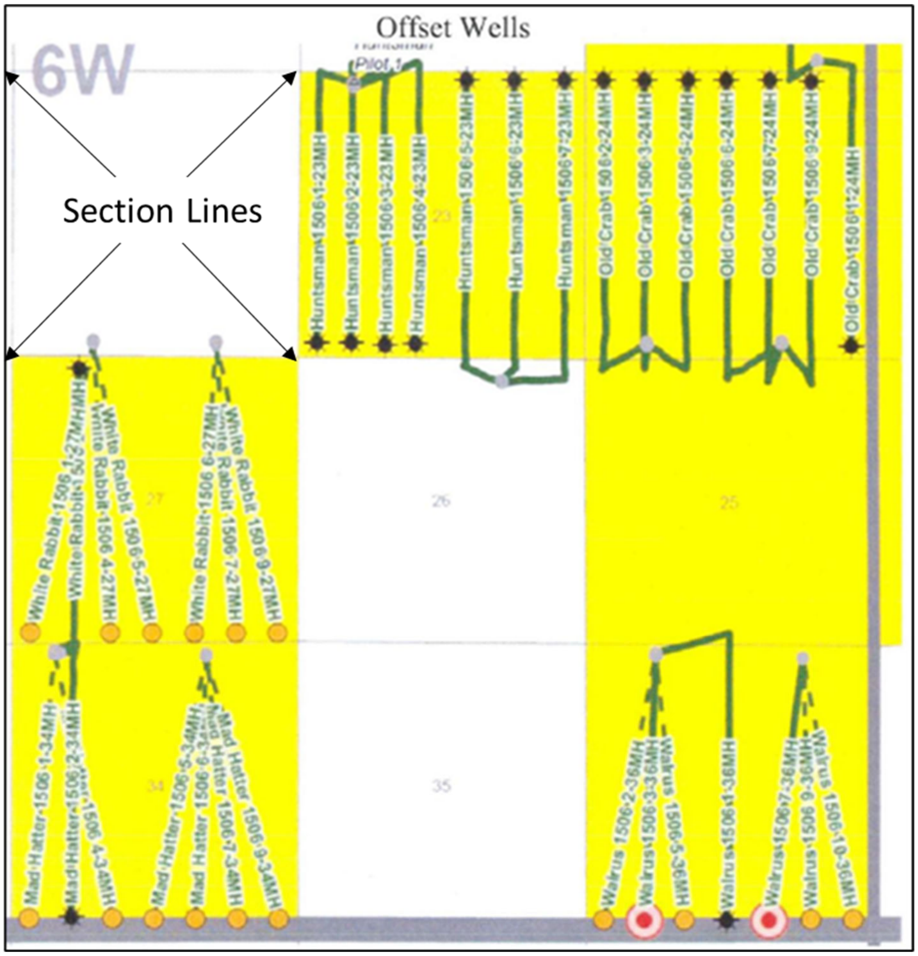

Figure 9 – Alta Mesa Land Map Showing Well Paths[15]

3. Benefits of S-Shaped Wellbores

In my experience, operators deploy S-shaped well designs to maximize both the horizontal extension of a well in the reservoir and the lateral length of the wellbore that can be stimulated and produced, improving overall reserve recovery. Improved recovery is realized at the heel of the well. *See* Point A in **Figure 8**. Although there is an incremental cost to drilling wells in this manner, that cost is generally viewed to be offset by the incremental reserve potential.

4. Use of S-Shaped Wellbores in the STACK

S-shaped wellbores have been drilled throughout the STACK. As of 2022, at least 13 operators that drilled horizontal Mississippian wells in Kingfisher County had drilled one or more S-shaped wellbores, as I use that term. **Figure 10** presents those operators in descending total well count (left to right), with total wells shown on the left axis, and the percentage of total S-shaped wells shown on the right axis. As depicted in **Figure 10**, Alta Mesa and Newfield Exploration Company (the latter company discovered the STACK play) have the highest overall well counts

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[15] *See* September 18, 2018 Board of Directors Meeting, Meridian_000000750 at -843.

and S-shaped wellbores. Devon Energy and Marathon Oil, both of which are significant operators in the oil and gas industry, also drilled S-shaped wellbores.

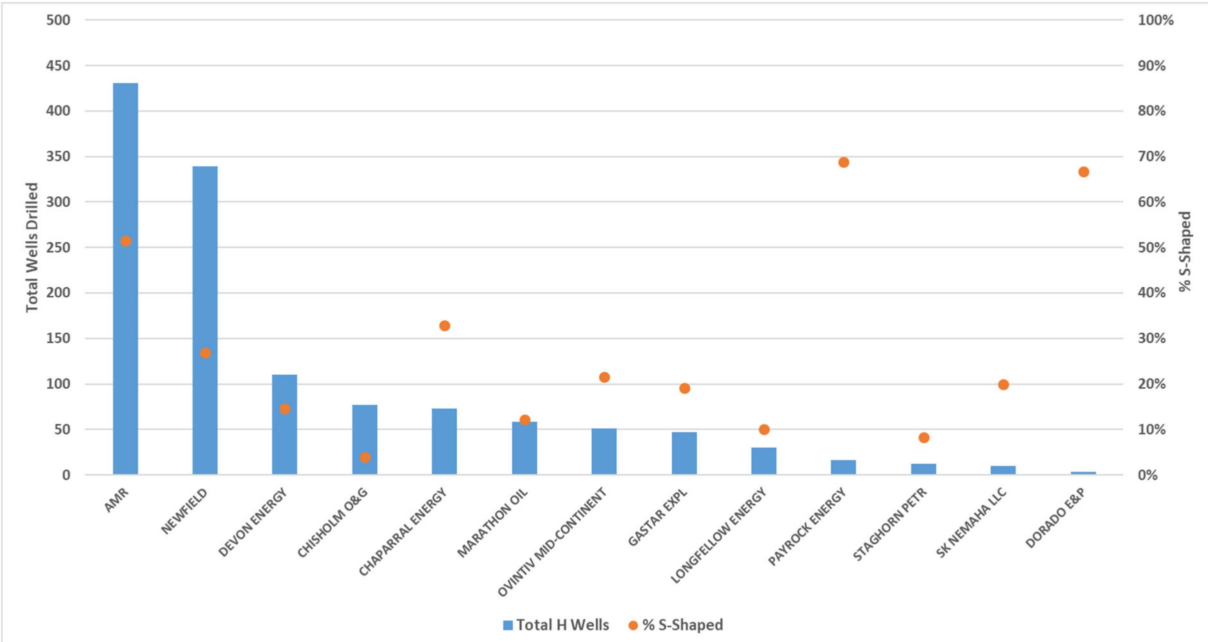

Figure 10 – Horizontal and S-Shaped Wells Drilled in Kingfisher County, by Operator

5. Impact of Well Deviation on Rod Lift

Rod lift (also known as "beam lift") is generally used in vertical wells or in horizontal wells with a low deviation angle from vertical; and as shown in **Table 1** above, rod lift is typically best applied during a well's mid- to late-life. Because rod lift uses a pump placed deep in the well (above the curve leading to the horizontal lateral), it achieves low bottomhole flowing pressures that generally lead to improved reserve recovery. Plunger lift can achieve similar recoveries if the producing conditions are favorable. This will be explained in Section IV.E, below.

Rod lift is the form of artificial lift that is most adversely impacted by the deviated path of the wellbore from the surface down to the curve, which is measured as DLS.[16] That is because the rods that run inside the tubing from the surface to the downhole pump are continuously stroking up and down, which causes wear on the rods and the tubing. DLS poses the greatest problems at shallower well depths, *i.e.*, from 0 to 1200 feet below the surface.[17]

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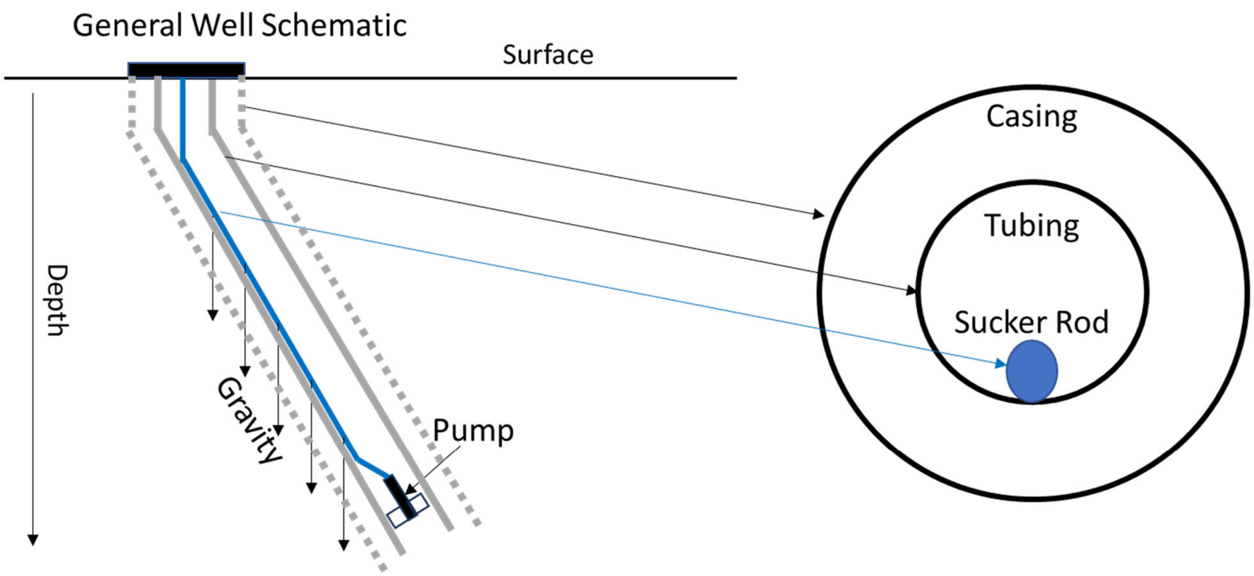
[16] DLS is defined as the change in a well's inclination over a 100-foot interval of the wellbore, and is calculated from a wellbore deviation survey.

[17] This is due to the creation of higher side loads (*i.e.*, weight) on the rod string at shallower depths due to the increased weight of the rod string below that depth that must be supported. This loading force can cause rod breakage or a hole to be worn in the tubing string.

Figure 11 shows a cross section of a wellbore at an angle. Notice how gravity pulls the rods to the low side of the tubing. When a well's DLS is closer to the surface, use of rod lift is limited or unavailable due to the greater stresses on the rods from supporting the weight of the rods below. Although rod lift is not usually recommended for wells having DLS greater than 5 degrees, one source notes that rod lift has been used in wells with DLS greater than 30 degrees.[18] Specialized software can model the unique shape of each wellbore and the use of load-reducing equipment to determine whether rod lift can be used in a particular well. This process should be followed when a well's DLS is greater than 5 degrees.[19]



A Build and Hold well path illustrating how gravity impacts the rods, causing them to lay and slide on the low side of the tubing

Figure 11 – Cross Section of a Rod Inside Tubing at an Angle

[18] *See* Hein, N., Oil & Gas Optimization Specialists, Ltd. And Rowlan, O., Echometer Company, SWPSC (2019), "Dog Leg Severity (DLS) and Side Load (SL) Recommendations to Drilling", Society of Petroleum Engineers.

[19] Although, as noted, the use of rod lift is limited by DLS in deviated wellbores, modeling software can be used to review a well's deviation profile and determine its capability for using rod lift. Equipment is also available to help reduce the loads on the rods. Such equipment includes: long stroke pumping units that provide a long, slow stroke instead of a shorter, faster stroke with more conventional pumping units; continuous rods that are of greater strength and do not have the coupling every 20 feet as with conventional rods; rod guides made of high-density plastic, placed at areas of greater DLS to reduce frictional wear on the rods and tubing; and roller guides also placed at areas of greater DLS to reduce frictional wear on the rods and tubing.

IV. ALTA MESA'S DEVELOPMENT OF THEIR STACK ACREAGE WAS REASONABLE FROM AN OPERATIONAL AND TECHNICAL PERSPECTIVE AND CONSISTENT WITH INDUSTRY PRACTICE

Alta Mesa's development of their STACK acreage has been criticized. Those criticisms, however, are not consistent with industry practice generally or with respect to operations in the STACK specifically. From my in-depth analysis of Alta Mesa's development approach—and based on my education, training, and experience—I find that (1) the Company's development of their STACK acreage was reasonable from both an operational and a technical perspective, and (2) the Company operated consistent with industry practice and reasonably based on information they had at the time.

A. Industry Interest in the STACK Coincided With and Matched Alta Mesa's Development Plans

From 2017 and into early 2018, both large and small oil and gas exploration companies invested heavily in STACK-focused drilling programs. Alta Mesa's drilling plans for the STACK play were commensurate with peer operators. Having reviewed public statements, investor presentations, and public filings from these peer companies, I conclude that Alta Mesa's 2018 drilling strategy was on par with its competitors. Similarly, Alta Mesa's operational assumptions about drilling potential in the STACK were not unlike those being publicized by competing companies in the STACK.

In November 2017, for example, Chaparral Energy, with acreage adjacent to Alta Mesa, announced that it would increase its STACK acreage by nearly 30 percent, sell all of its non-STACK assets, and become a pure-play STACK operator.[20] According to the company, "from 2016 to 2018, we increased our STACK production at a compound annual growth rate of approximately 39%."[21] Between 2017 and 2018, Newfield Exploration, another large STACK operator, invested more than $1 billion in its STACK and SCOOP operations.[22] According to Newfield in early 2018, the STACK was best "characterized by wells with consistent and strong production rates, high initial oil cuts and low operating expenses."[23] For 2018, in particular, Newfield allocated approximately 80% of its overall investment budget for drilling and completions in the STACK and SCOOP plays.[24] Other STACK operators were promoting similarly promising expectations for the STACK in early 2018. In May 2018, for example, Devon

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[20] *See* "Chaparral Energy Closes EOR Asset Sale for $170 Million, Transitions to Pure-play STACK Operator," Chaparral Energy Inc. Press Release, Nov. 20, 2017; *see also* "Chaparral Energy Announces Bolt-on STACK Play Acreage Acquisition in Kingfisher County, Oklahoma," Chaparral Energy Inc. Press Release, Dec. 27, 2017.

[21] Chaparral Energy Inc., 2018 Form 10-K, at 7.

[22] Newfield Exploration Company, 2017 10-K, at 4-5.

[23] *Id.*

[24] *Id.*

Energy cited the company's confidence in the STACK's productivity as one reason for increasing its full-year oil production forecast.[25]

B. Timing Assessment of Alta Mesa's Development Execution

It is also claimed that Alta Mesa failed to act timely to modify its 2018 drilling plans after receiving disappointing results. Examples of then-available information reveal a different story. Throughout early and into midyear 2018, Alta Mesa's management team was monitoring the Company's performance, including specifically well operational performance. Alta Mesa's management did not wait idly until late 2018 to react. On the contrary, the Company was mindful of well performance issues and it reacted timely. I have reviewed Company announcements and deposition testimony in this matter (see Appendix B), and conclude that Alta Mesa was actively tracking operational performance while considering appropriate responses.

For instance, during his deposition for the Trustee matter, Alta Mesa's former CEO, Hal Chappelle, discussed email correspondence with colleagues about Alta Mesa's well performance in and around April 2018.[26] Mr. Chappelle's testimony highlights that Alta Mesa management was actively discussing appropriate actions relating to operational performance in early 2018. He explained that Alta Mesa's management was then "debating, recognizing where the data of the wells drilled to date have been and . . . what we're doing to understand the effects of that and how to improve on that."[27] He added: "[the relevant email exchange] is a healthy dialogue over what the EURs ultimately could end up being."[28] Another senior official at Alta Mesa, Tim Turner, testified similarly. Mr. Turner explained during his deposition that, in early 2018, Alta Mesa was running a variety of tests to monitor well productivity, which—based on the information available at that time—supported the Company's drilling strategy.[29] Mr. Turner explained, for example: "I think virtually every pattern that we drilled except maybe one or two was well above our PV-10 type curve. So, we were generating good economic wells. Whether or not they were below the type curve, they were still economic. . . So yes, it would have made sense in my view to drill."[30] Further to this point and as shown in the email that I have cited above (*i.e.*, AMR_SDTX00672982), Mr. Turner and others at Alta Mesa understood that the Company's "[p]atterns [we]re still early" as of April 2018.[31]

Deposition testimony from other individuals with close knowledge of Alta Mesa's management reflects a similar accounting of the Company's then-available understanding of the STACK play. Jim Hackett, Chairman of Alta Mesa's Board of Directors, explained during his

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[25] "Devon Energy Reports First-Quarter 2018 Results," Devon Energy Corp. Press Release, May 1, 2018.

[26] *See* AMR_SDTX00672982.

[27] H. Chappelle Trustee Depo. Transcript at 144; 4-9.

[28] *Id.* at 144; 16-18.

[29] *See* T. Turner Class Action Depo. Tr. at 72; 5-24.

[30] *Id.*

[31] AMR_SDTX00672982.

deposition that—throughout 2018, including the year's earlier months—Alta Mesa management was reviewing and analyzing operational performance data in a fashion that is typical and expected of public company management teams.[32] Mr. Hackett remarked that in April 2018, Alta Mesa management was "looking at every piece of data and working on it, trying to figure out what they ought to change or do differently, what's working" and noted that "[t]his would be very typical for a management team to be exchanging this kind of information."[33]

Further to a point discussed more thoroughly below—that Alta Mesa needed several months to acquire data before being able to reach conclusions about well performance—deposition testimony in the Trustee and Class Action litigation shows that Alta Mesa engineering personnel were of a similar mind. Mr. Turner explained, for example: "You know, you're four to six months from turning on production to really feeling confident in your forecast."[34] Jack Albers, a former engineer for Alta Mesa, raised similar points during his deposition. He explained, for instance, that "[e]arly on in a well's history it is very difficult to determine where the well is going as far as production. You have very few data points."[35] Mr. Albers also remarked: "the fact is only having a few points, being a few months of production, means the numbers are no doubt going to change."[36] During his deposition, Mr. Albers also explained that with more time, Alta Mesa could collect more data and thus "get more accurate over time, yes."[37]

To provide context for my analysis and conclusions regarding Alta Mesa's execution of its development plan, I have listed the following key events and dates:

- <u>May 2017</u>: The beginning of Alta Mesa's multi-well pattern development, in which it transitioned from well-spacing pilots to multi-well patterns, which began with the drilling of the Ash-Foster pattern.[38]
- <u>November 2017</u>: First production from the Ash-Foster pattern.
- <u>February 2018</u>: Shareholders vote to create Alta Mesa Resources.
- <u>June 2018</u>: The first month in which Alta Mesa had meaningful, but disappointing, flow data from all of the first six multi-well patterns, which were spud from May-September 2017. These results showed that more work needed to be done to identify the reasons for the disappointing results. Additional work included installing more ESPs.

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[32] J. Hackett Trustee Depo. Tr. at 47; 18-24.

[33] *Id.*

[34] T. Turner Trustee Depo. Tr. at 120; 5-7.

[35] J. Albers Class Action Depo. Tr. at 137; 2-4.

[36] *Id.* at 137; 11-12.

[37] *Id.* at 137; 20-22.

[38] Alta Mesa spud seven well-spacing pilots between March 2014 and February 2017, which had first production between June 2014 and August 2017. Those pilots predate Alta Mesa's multi-well development patterns, which were the focus of the development strategy.

- June-September 2018: Alta Mesa continued to assess production data from the first six patterns, early flow data from new patterns coming online as shown in **Table 3**, and certain wells' responses to ESP installations. Alta Mesa investigated whether to revise their number of wells per section in light of these data.
- September 2018: Alta Mesa determines that three- and four-well patterns (with 1500-foot in-bench well spacing) were the best performers among its patterns.[39]
- October 2018: Alta Mesa began limiting infill wells to four or fewer wells per section, with most being three wells.

Alta Mesa conducted all of the above operations across a timespan lasting approximately 17 months. Overall, from November 2017 through October 2019, Alta Mesa brought online 209 child and infill parent wells[40] and 52 parent/sibling wells, and it developed a total of 52 multi-well patterns, testing various well spacings and fracture-stimulation designs.

Table 3 shows the well spud date and first production date for all 52 multi-well patterns, with the first six patterns highlighted. Parent (*i.e.*, single) wells were also being drilled across Alta Mesa's acreage throughout 2018.

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[39] *See* September 18, 2018 Board of Directors Meeting, Meridian_000000750, slides 194-195.

[40] "Infill parent well" is defined in footnote 48.

Table 3 – Multi-Well Patterns Spud & First Oil Production Dates

Count	Pattern	First Spud Date	Date of 1st Production
1	Ash-Foster	5/14/2017	11/4/2017
2	Hoskins	6/9/2017	12/17/2017
3	Themer	6/22/2017	11/28/2017
4	Paris	8/9/2017	1/4/2018
5	Todd	8/18/2017	1/22/2018
6	Lankard	9/12/2017	1/18/2018
7	James	10/13/2017	4/22/2018
8	Zeppelin	11/3/2017	4/5/2018
9	The Trick	11/16/2017	3/22/2018
10	Niko	11/29/2017	4/16/2018
11	Odie	1/1/2018	5/18/2018
12	Red Queen	1/13/2018	5/25/2018
13	Huntsman Old Crab	1/19/2018	5/31/2018
14	Oak Tree	1/28/2018	5/4/2018
15	SE-Slaughter House	2/18/2018	8/14/2018
16	Speyside	2/26/2018	5/16/2018
17	Peat	3/5/2018	6/17/2018
18	Greene-Mackey	3/13/2018	7/2/2018
19	Sawgrass	3/15/2018	6/25/2018
20	Slugworth	4/20/2018	7/30/2018
21	Whiskeyfeet	5/4/2018	8/28/2018
22	Redbreast	5/12/2018	9/23/2018
23	Daydrinker	6/5/2018	9/1/2018
24	Walrus	6/11/2018	9/30/2018
25	White King	6/14/2018	9/28/2018
26	Dalwhinnie	7/4/2018	10/22/2018
27	Mad Hatter	7/4/2018	10/27/2018
28	White Rabbit	7/17/2018	11/2/2018
29	Bollenbach - sec 21	8/3/2018	11/19/2018
30	Boecher	8/29/2018	11/17/2018
31	Cheshire Cat	8/31/2018	11/24/2018
32	Fazio	9/3/2018	12/15/2018
33	Bollenbach - sec 27	10/8/2018	12/8/2018
34	Tullamore	10/10/2018	12/24/2018
35	Lil Sebastian	10/14/2018	1/18/2019
36	Sadiebug	10/31/2018	2/20/2019
37	Evelyn	11/1/2018	4/4/2019
38	Cleveland	11/10/2018	2/26/2019
39	Towne	11/17/2018	3/29/2019
40	EHU 255/257/259	11/17/2018	4/23/2019
41	EHU 252/254/256/258	12/3/2018	4/13/2019
42	Kilgore	12/19/2018	4/12/2019
43	Helen	12/19/2018	4/12/2019
44	Edwin	3/1/2019	5/11/2019
45	Aberfeldy	3/2/2019	5/10/2019
46	Mouse Rat	4/9/2019	7/3/2019
47	Bunker Buster	4/11/2019	7/11/2019
48	Aces High	5/16/2019	7/25/2019
49	Mayes-Schilde	5/21/2019	7/26/2019
50	Wakeman	6/13/2019	8/30/2019
51	Brown	6/20/2019	8/22/2019
52	Hasley	7/24/2019	10/25/2019

1. Time Lag from Spud to First Production

As discussed in Section III.B.3, there is a necessary and unavoidable time lag between the date a well is drilled (*i.e.*, "spud") and when first production is realized. This is due to the fact that after wells are drilled, production facilities must be built, all wells must then be fracture-stimulated, and finally all wells must be equipped to flow with tubing and artificial lift. These activities typically require even more time when multiple wells are drilled from a single surface pad.

Figure 12 shows, in chronological order starting in January 2014, the time interval between spud of the first Alta Mesa well-spacing pilots and later multi-well patterns and the first production from those pilots and patterns. I have noted the ramp-up in development drilling starting with the Ash-Foster pattern in May 2017, and its first production date in November 2017.

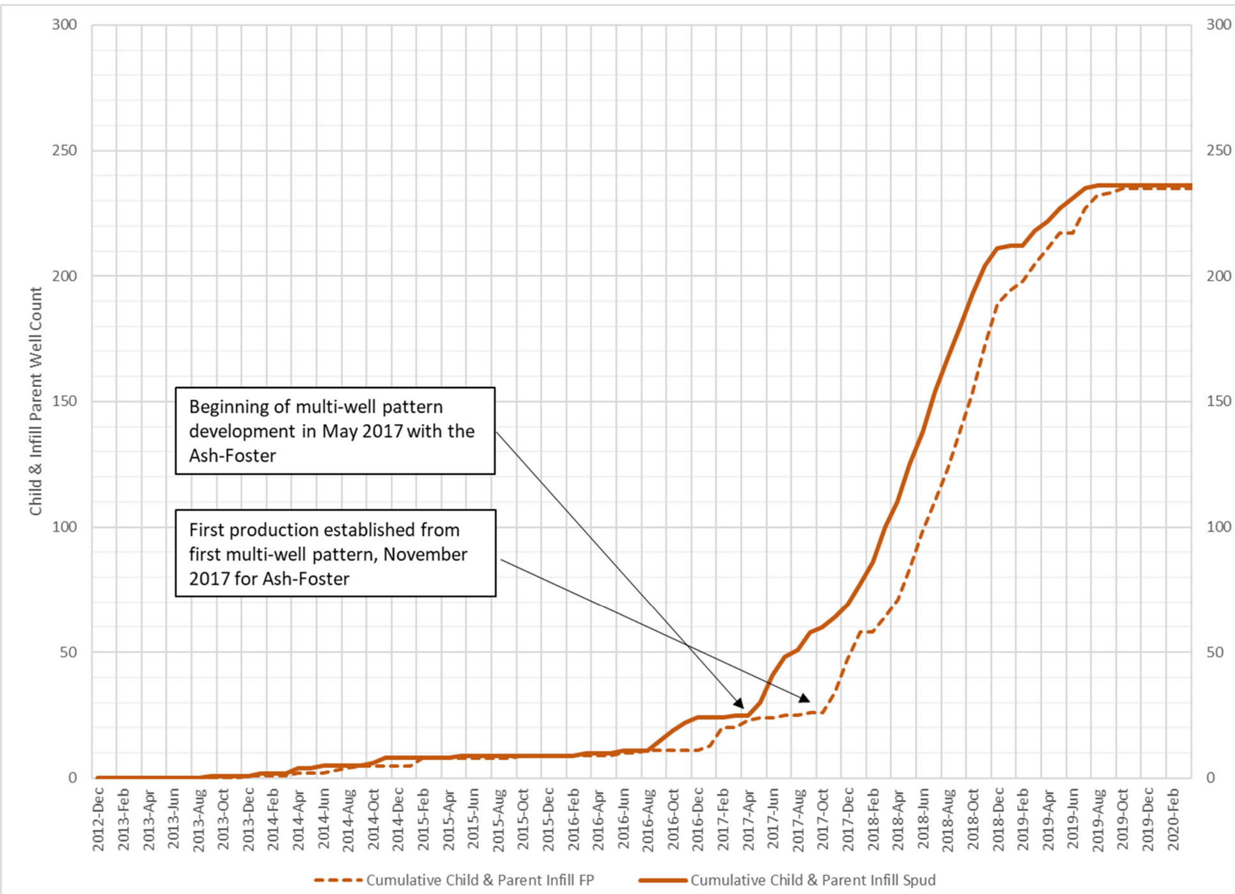

Figure 12 – Total Infill Well Count Showing Dates of Spud to First Production from Alta Mesa's Multi-Well Patterns

Note two points from **Figure 12**: (1) the spud-to-first-production time for these wells was not significantly affected by the number of wells in a pattern; and (2) Alta Mesa became increasingly efficient over time in shortening the time between spud and first production. The data show that the average timespan from the first child well spud in a pattern to the pattern's first production is 117 days, with the minimum and maximum intervals being 61 and 198 days, respectively. The range of days for each pattern is shown in **Figure 13**, below. As can be seen in

the Figure, the timespan from spud to first production decreased significantly from July 2017 through July 2019.

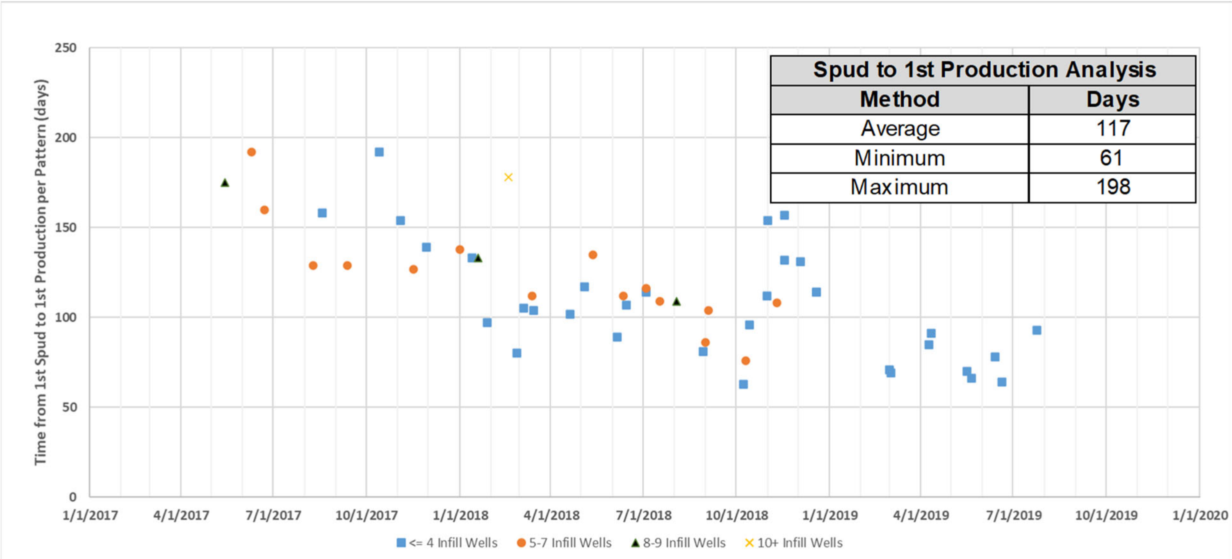

Figure 13 – Time from Spud to First Production for each Alta Mesa Pattern

2. Production History Required to Assess Well Performance

Several months of production history are required before a newly on-line well can be assessed and a forecast for that well generated. After a well is opened to flow, the primary flow is frac water until the excess pressure imposed on the reservoir by the fracture-stimulation fluids is reduced below reservoir pressure. At that point, hydrocarbons begin to flow and the well continues to "clean-up"—*i.e.*, the production of fracture-stimulation fluids gradually diminishes, reducing pressure in the wellbore and allowing hydrocarbons to flow at increasing rates. During this time, water production in these wells continues to decrease, and oil and gas production continue to increase until hitting a peak, at which point production rate begins to decline.

This is illustrated in **Figure 14**, which shows the rate and timing of water, gas, and oil from the Alma 1-20MH well.[41] Using this type of plot, an experienced petroleum engineer can

[41] The data in **Figure 14** are plotted in semi-log format, meaning the X-axis (showing time intervals) uses a linear scale and the Y-axis (showing well-production data) uses a logarithmic scale. Well-production data includes: *Calendar day ("Calday") Oil* ("bopd" or "bbl/d"), the monthly produced oil volume in barrels divided by the number of days in that month; *Calday Water* ("bwpd" or "bbl/d"), the monthly produced water volume in barrels divided by the number of days in that month; *Calday Gas* ("Mscfd" or "Mscf/d"), the monthly produced gas volume in 1000 standard thousand cubic feet ("Mscf") divided by the number of days in that month; *GLG Inj or Gas Lift Gas Injected* ("Mscfd"), the amount of gas-lift gas injected into the wellbore annulus that will enter the tubing at some deeper depth and mix with the produced fluids and gas to lessen the effective density of the produced column and improve the well's ability to flow; *Water Cut (%)*, the Calday Water divided by the sum of the Calday Water plus Calday Oil; and *GLR ("scf/bbl") or Gas Liquid Ratio*, the Calday Gas (in Mscf) divided by the sum of the Calday Oil

recognize various aspects of a well's production performance—*e.g.*, a well that might be loading with liquid, a well that is not being produced efficiently as evidenced by continuous up and down character of the gas-oil ratio ("GOR"), production rates, etc.[42] Further, this figure illustrates that, on average, a minimum of 120 days of production from first flow is needed before the well's decline rate begins to follow a trend that, in my opinion, is more predictable (consistent in its rate of decline), which allows for the earliest prediction of EUR.

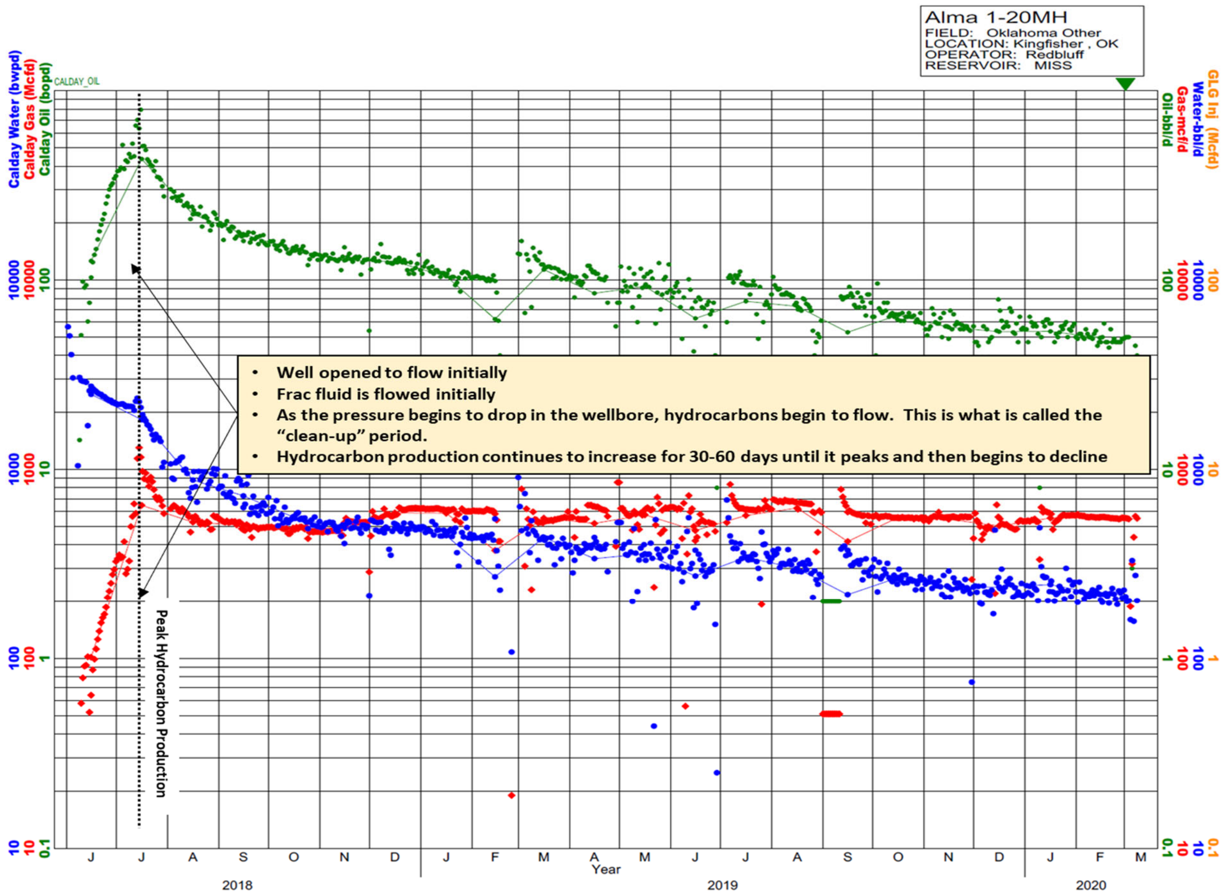

Figure 14 – Initial Well Clean-Up Flow Characteristics

3. Time Required to Compare Well Performance to Type Curve Expectations

An industry standard for analyzing the performance of an unconventional well is a plot of the well's cumulative oil production over time compared to its pre-drill predicted production. As described previously, the pre-drill forecast is referred to as a "type curve" or "type well." Type-curve analysis can be applied to parent, child, and sibling wells on an individual basis.

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and Calday Water. GLR is the rate of lower-density flowing gas to the rate of flowing liquid. This ratio is an indicator of how efficiently the well will produce (*i.e.*, "lift") on its own from the reservoir's native pressure, and can help determine what type of artificial lift might be best suited for the well.

[42] Production plots for all of Alta Mesa's horizontal wells are included in Appendix D to this report.

Additionally, a pattern average of all wells (parent, child and/or sibling) may be plotted on a single graph to compare multiple patterns against the type curve. **Figure 15** shows a plot of the ten wells from the Huntsman-Old Crab pattern and a 250,000 barrels of oil (250 MBO) type curve.

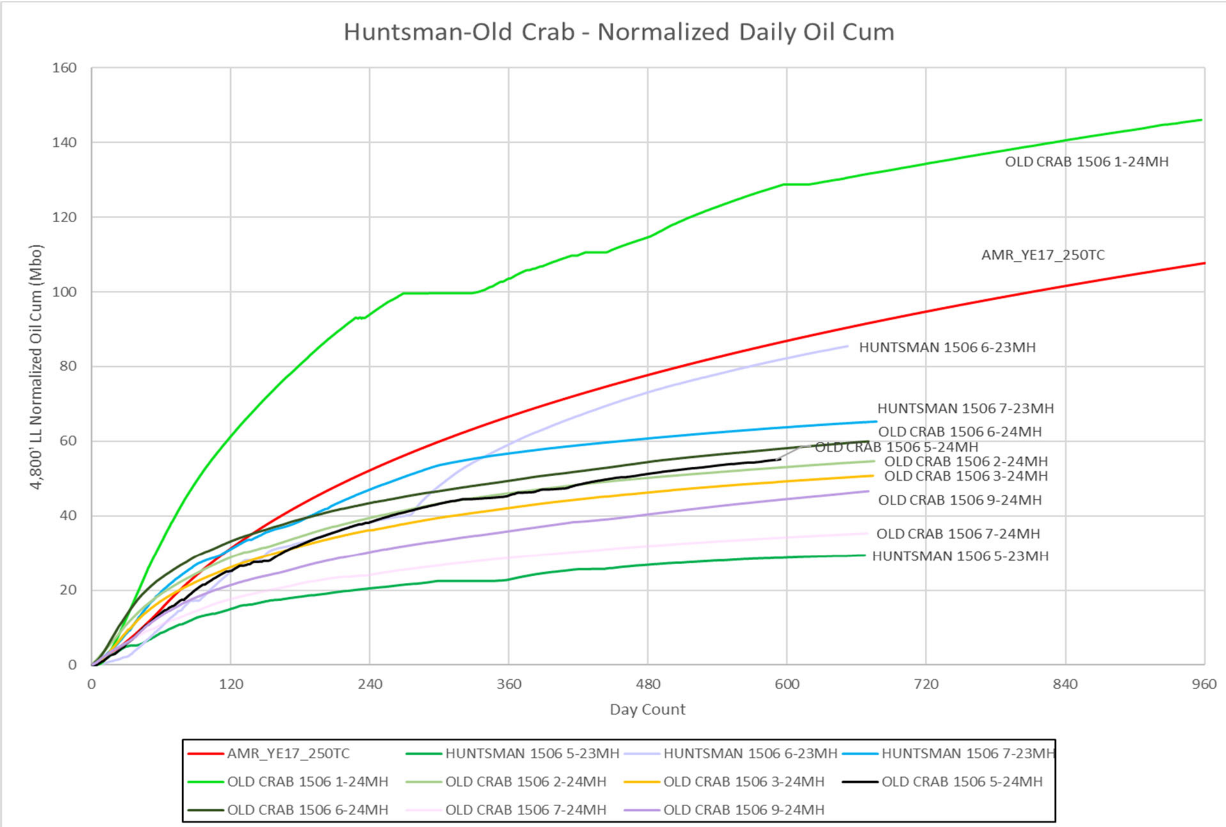

Figure 15 – Normalized Cumulative Oil Plot for a Pattern

This plot shows that the parent well, Old Crab 1506 1-24MH (light green line on Figure 15), has the longest producing time of the ten wells. The child wells have less producing time than the parent well. An observation here is that a number of the child wells were exceeding the type curve until approximately 120 days. The number of producing days considered is important to making an accurate assessment of a well's performance relative to the type curve. A plot like this was generated for all 59 of Alta Mesa's spacing pilots and multi-well patterns and is included in Appendix E.

Based on my extensive experience reviewing day-to-day well performance of unconventional wells, and reviewing the normalized cumulative oil plots for all 59 of Alta Mesa's well pilots and multi-well patterns, I concluded that the performance of each Alta Mesa well relative to the type curve can reasonably begin to be first assessed, in most instances, after a minimum of 120 days of production (120 days is represented by the first vertical grid line on

Figure 15). That period allows the wells to clean up and stabilize to a point where their production rate is more predictable.[43]

Note that a well can be producing at a cumulative oil value above the cumulative oil type curve at a given time, whereas a projection of the production trend (as represented by the slope of the line) for the last several days or weeks indicates that it will also begin to underperform at some point. The Old Crab 1506 6-24MH child well in **Figure 15** is a good example of this.

Alta Mesa also generated plots of "normalized cumulative oil" (commonly used in the industry and consistent with practice), which compare the *average* well performance for multiple patterns against the 250 MBO type curve. An example of this plot is provided below in **Figure 16**.[44] The four plots show the same well patterns but with different producing time frames. From the lower-left graph, one can project that, at 120 days of production, all of these patterns are likely to underperform the 250 MBO type curve. Note, however, that the EHU pattern appears to be on a trend to overperform the type curve at some time after 365 days. This is unusual, but it can happen. Based on Alta Mesa's data here, 120 days of normalized cumulative oil was generally required in most cases to begin to make a fair assessment of pattern performance relative to the 250 MBO type curve.

[43] As previously discussed, 120 days is on the low end of the amount of production data needed to begin to make such an assessment.

[44] *See* AMR_SDTX00003589 at -3600 ("YE2018 Reserve Report Pattern Analysis and Assessment" (December 2018)).

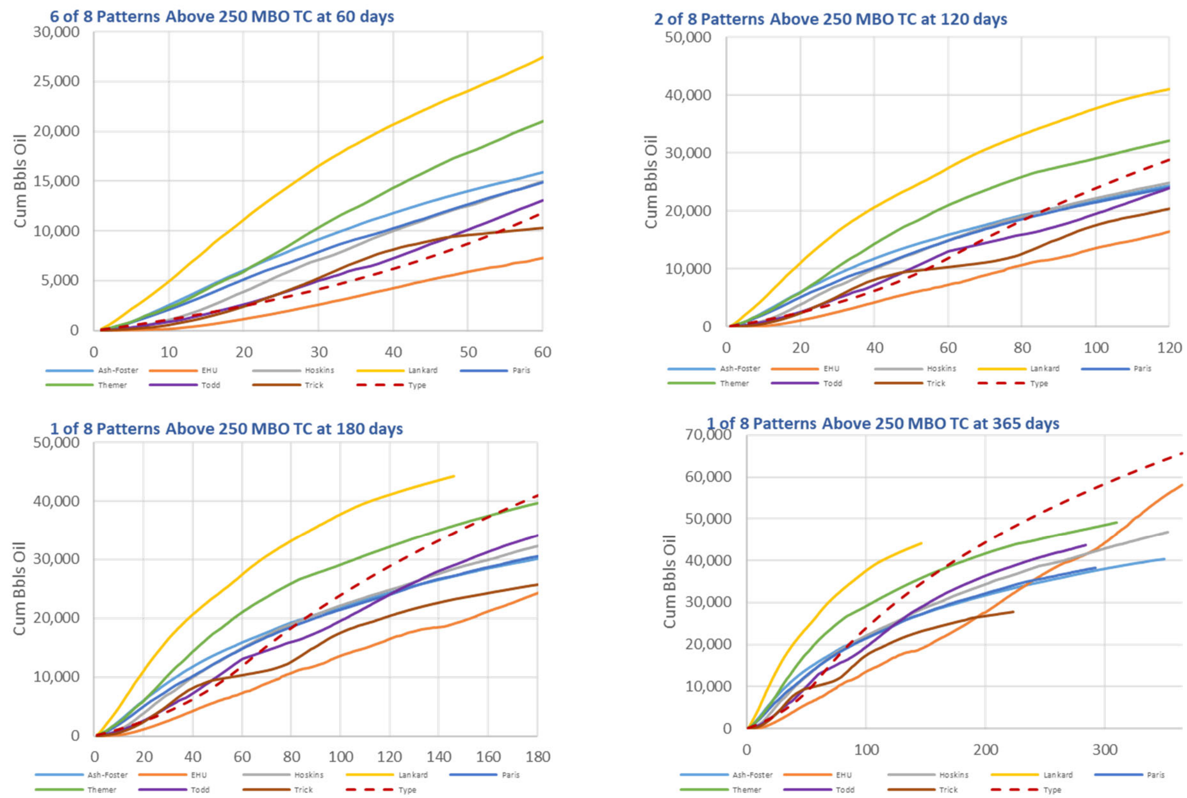

Figure 16 – Alta Mesa Normalized Cumulative Oil Plots

Based on the above assessment of Alta Mesa's multi-well patterns, it is my opinion that at least 120 days, or four months, of production data were required from the date of first production from all wells in the patterns to allow Alta Mesa to begin to make a reasonable assessment ("First Assessment Date") of their patterns' performance. As discussed below, although no conclusive determinations could yet be made, Alta Mesa had enough production information at this point to determine that more investigation was needed to determine whether well-performance could be improved, and if not, what course corrections needed to be made.

4. Time Lag from Spud to First Production and Assessment

Figure 17 adds the First Assessment Date to the spud- and first-production dates shown in **Figure 12** for Alta Mesa's multi-well patterns. From this analysis, it is clear that for the six multi-well patterns that were spud between May and September 2017, the first production from which occurred between November 2017 and January 2018, meaningful well performance was not available from all of them until June 2018.

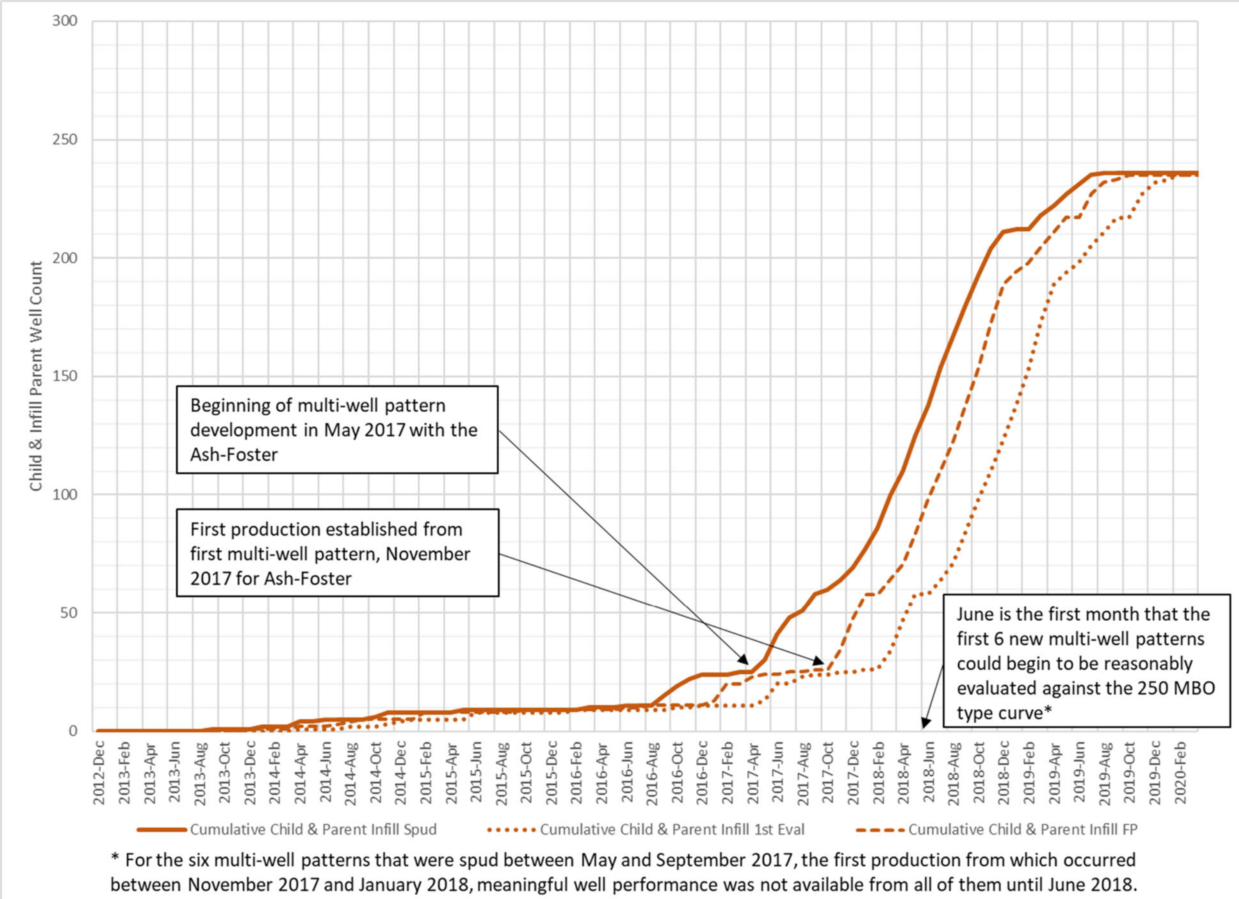

Figure 17 – Figure 12 with Pattern Evaluation-Time Curve Added

5. Multi-Acreage Development and Assessment

It is not practical to make multi-acre development decisions from the results of a single pattern, or even from several patterns unless sufficient data are available. Instead, multiple patterns need to be assessed before adjustments, if necessary, are made. Assessment of multiple patterns is critical to decisions regarding capital expenditures, which are a primary focus during development planning and execution. As noted above, the six patterns from the Ash-Foster through the Lankard, as listed in **Table 3**, provided enough production information to begin to make a fair assessment after sufficient flow data was obtained by June 2018 (note that subsequent patterns did not have 120 days of production history until late July). At that point, Alta Mesa continued to implement its development plan while continuing to assess the incoming data and taking steps to improve the results.

Early in field development, there is a tendency to drill more wells than are ultimately required. An important lesson from my experience in the STACK and other plays is that, once a unit is developed, it can neither be re-drilled nor re-stimulated, potentially stranding reserves in the reservoir. In fact, there is a general view in the industry that before adequate data has been

collected, it is better to slightly over-drill a prospect than under-drill. This was evident in what offset operators were doing in the STACK during 2017-2018, when there was a tendency for higher well counts than in later years.

Figure 18 shows the number of wells per section that were being drilled by Alta Mesa and other STACK operators in Kingfisher County from 2016 through 2020. A vertical line at October 2018 indicates the month that Alta Mesa reduced their wells per section going forward. As shown, other operators were drilling more wells per section than Alta Mesa from 2016 through September 2018, and other operators were still drilling at higher wells per section than Alta Mesa after October 2018.

The map in Figure 19 shows Alta Mesa's land position in Kingfisher County, their wells, and the wells of offset operators (*i.e.*, operators in Sections in Ranges 5W-7W of Kingfisher County). **Figure 20** shows the wells per section for those offset operators over the same time period as **Figure 18**. It, too, shows that offset operators were drilling more wells per section than Alta Mesa after October 2018.

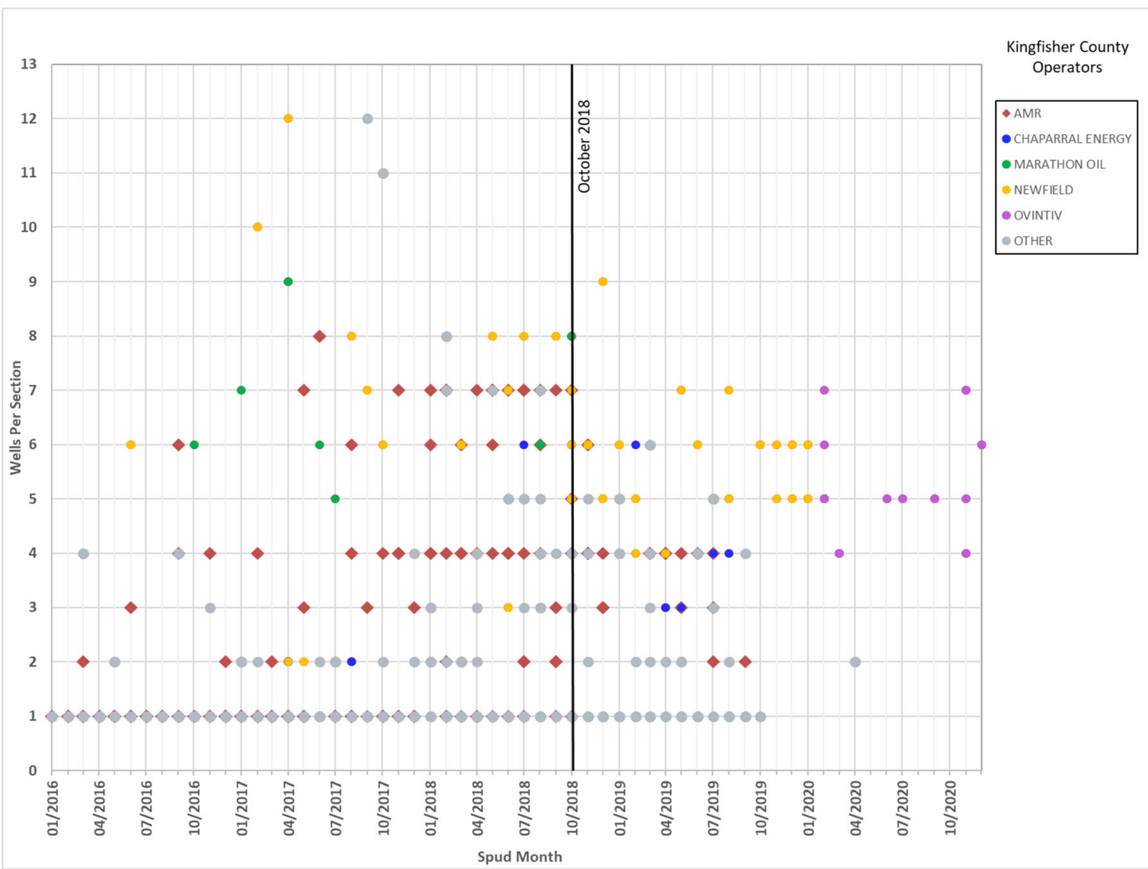

Figure 18 – Wells Per Section in Kingfisher County by Operator

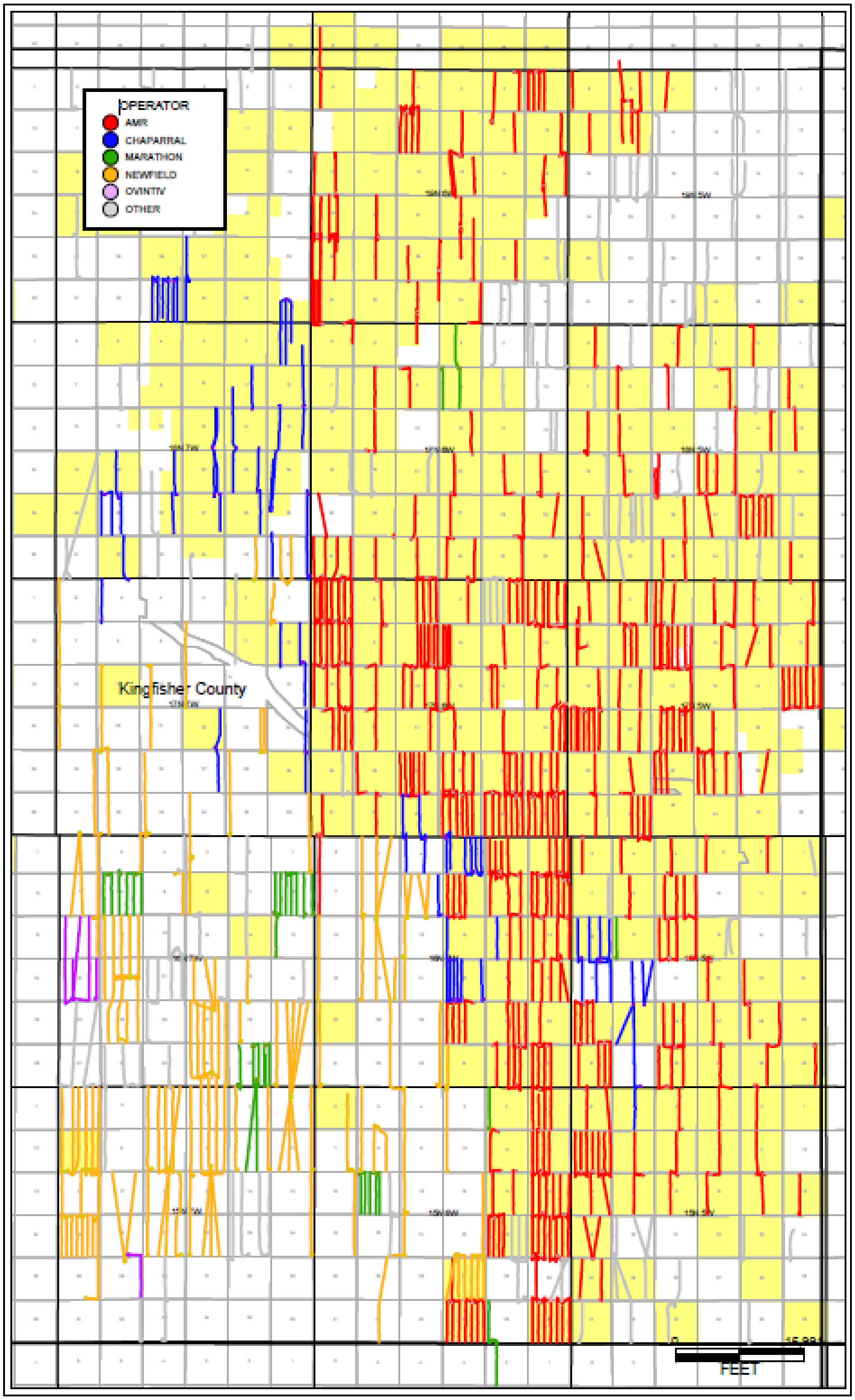

Figure 19 - Land Map of Alta Mesa Position (Yellow) and Alta Mesa Wells (Red) and Wells of Offset Operators

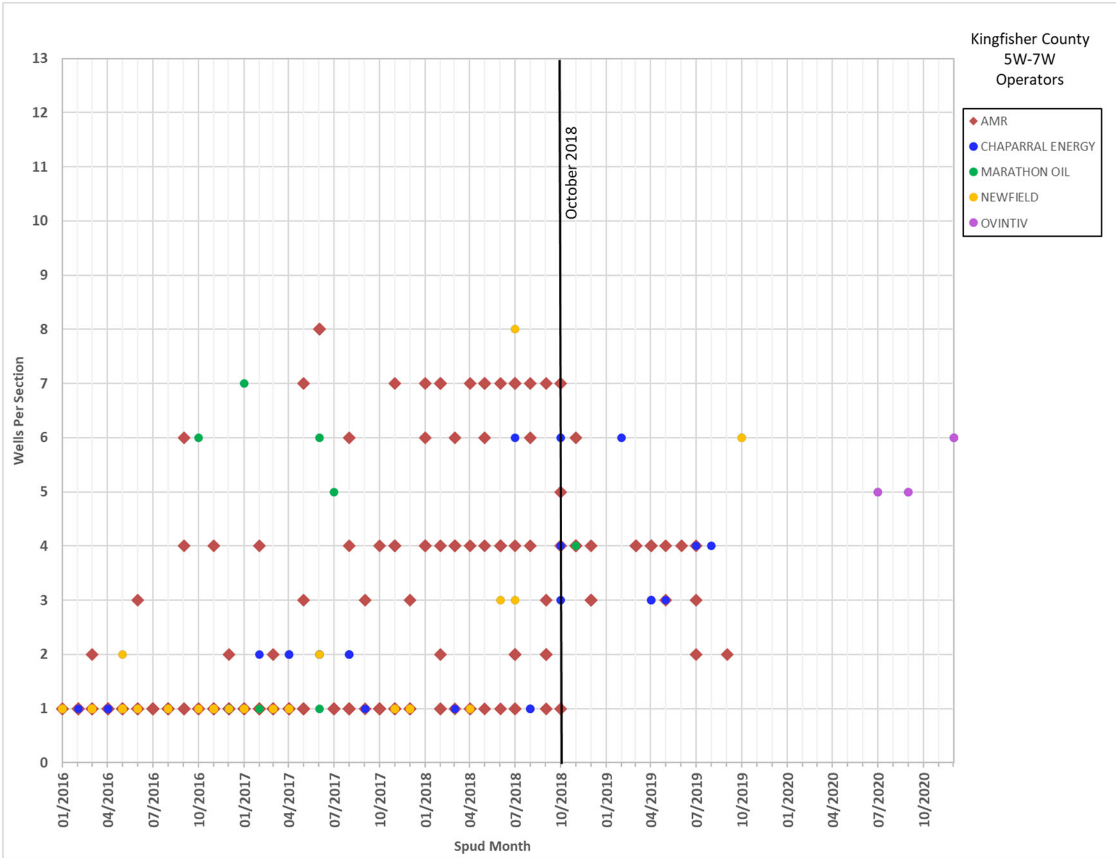

Figure 20 – Wells Per Section of Alta Mesa and Their Offset Operators

The map in **Figure 21** shows Alta Mesa's acreage position in yellow. Data for the first six multi-well patterns are shown in **Table 4** below, which adds the 120-day period from Initial Oil Production to First Assessment Date to show (as previously discussed) the earliest date by which Alta Mesa had sufficient production data from all of these six patterns—June 2018—to begin to make a fair assessment of well performance.

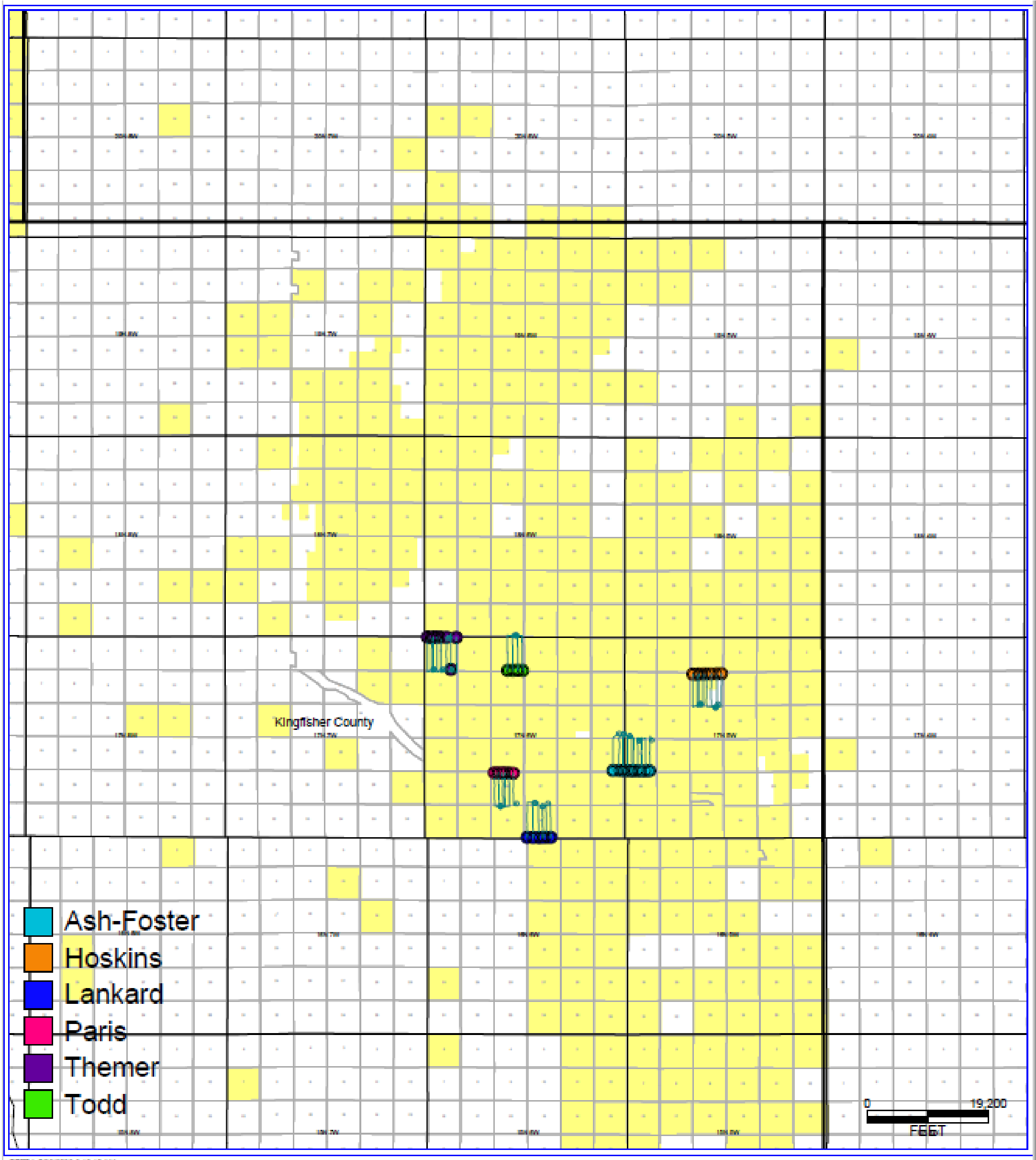

Figure 21 – Alta Mesa Acreage Map Showing The First Six Multi-Well Patterns

Table 4 – First Assessment Date for Six Multi-Well Development Patterns (Spuds beginning May 2017)

PATTERN	FIRST SPUD DATE	FIRST PRODUCTION DATE	DELTA	FIRST ASSESSMENT DATE
Ash-Foster	5/14/2017	11/4/2017	174	3/4/2018
Hoskins	6/9/2017	12/17/2017	191	4/16/2018
Themer	6/22/2017	11/28/2017	159	3/28/2018
Paris	8/9/2017	1/4/2018	148	5/4/2018
Todd	8/18/2017	1/22/2018	157	5/22/2018
Lankard	9/12/2017	1/18/2018	128	5/18/2018

Figure 22 shows, for Alta Mesa's 52 multi-well patterns (the first of which had initial production in November 2017), the time of first production and the cumulative number of infill (*i.e.*, "child") wells drilled. The drilling of these patterns began in May 2017 with the Ash-Foster pattern.

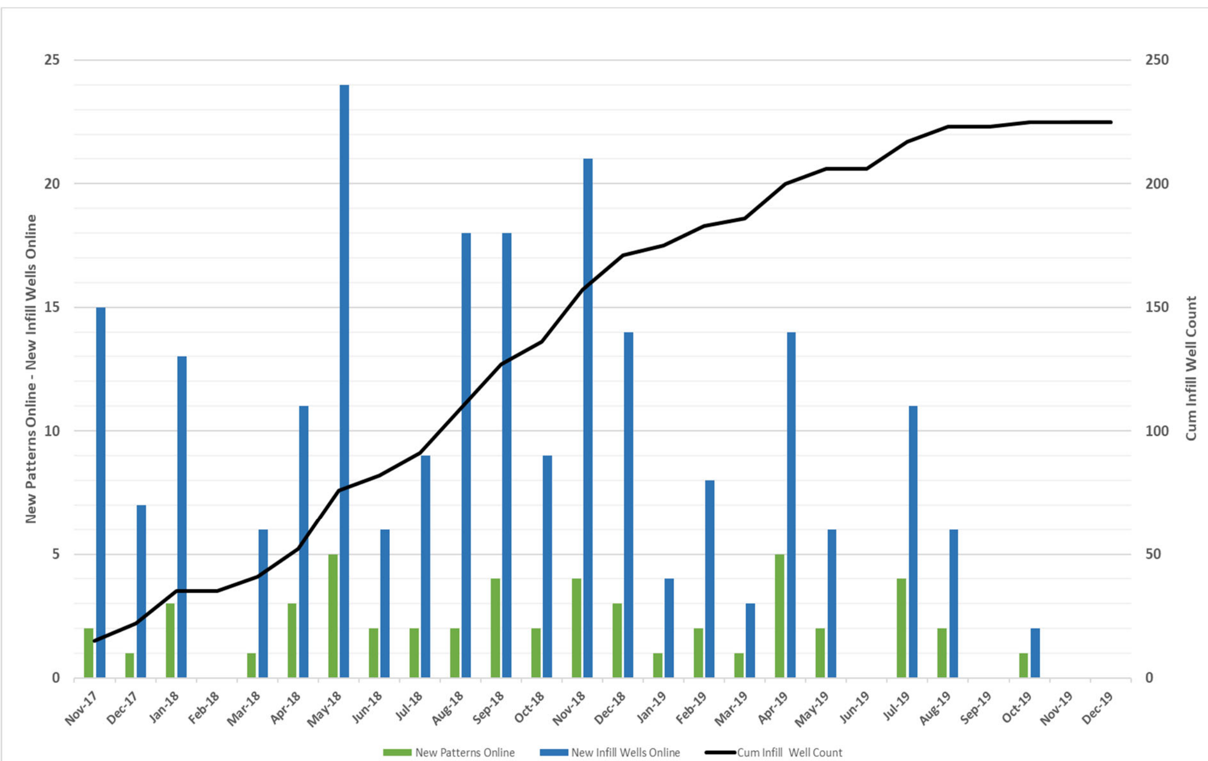

Figure 22 – Timing of Development Patterns and Well Count

After Alta Mesa received the initial production results from the six patterns that were drilled beginning in May 2017, it continued to assess the data and look for ways to improve

performance, including by means of artificial lift. Among other steps, Alta Mesa began installing ESPs at greater scale beginning in May 2018 when ESP installations showed positive results. Following are two examples:

- Ash 1705 4B-19MH: This well was not being efficiently gas lifted after completion, producing at a rate of 1-3 barrels of oil per day prior to installation of an ESP on April 29, 2018. After installation the rate increased to 60 barrels of oil per day by mid-May.[45]

- The Trick 1706 1-2MH: This well had been hit by an offset frac. Gas lift was able to restore production to 90 barrels of oil per day after the hit. However, after an ESP was installed May 4, 2018, oil rates increased further to a rate of 460 barrels of oil per day on July 8, 2018.

6. Alta Mesa Correctly Used ESPs to Increase Well Production and Isolate Problems with Well Performance

Because wells, once drilled and fracture-stimulated, can neither be re-drilled nor re-stimulated, the best way to isolate a production issue is to ensure that the wells are being lifted effectively. Therefore, when wells underperform, operators often turn first to evaluation of artificial lift because it can be tested quickly and changed if needed. Consistent with that strategy, Alta Mesa installed ESPs in a number of wells when performance was lagging below the type curve. ESPs improve a well's productivity by reducing bottom-hole flowing pressure, thereby reducing the hydrostatic backpressure being imposed on the reservoir. In my experience, use of an ESP is the most definitive method, compared to other forms of artificial lift, to maximize production.

Figure 23 adds ESPs installed (red bars) to **Figure 22**. As shown there, Alta Mesa installed ESPs on more wells coinciding with disappointing results from the six early patterns and Alta Mesa's need to understand the reason(s) for the underperformance. The cumulative number of ESPs installed is shown in the dotted black line. Alta Mesa's increased use of ESPs from May-October 2018 was effective in increasing well production and in restoring frac-hit wells to prior production levels. Increased use of ESPs was also beneficial because the resulting additional well data suggested that the well-underperformance was due primarily to well spacing, and not lift.[46]

Alta Mesa began to remove the ESPs starting with three in September 2018. *See* section IV.C below for a more complete discussion regarding Alta Mesa's use of ESPs.

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[45] The optimism created by this result is reflected in Alta Mesa CEO Hal Chappelle's reaction: "So much to be hopeful about." AMR_SDTX00669248.

[46] AMR_SDTX00672982 (showing Alta Mesa's Tim Turner writing: "Agree. I don't think we should hide it. . . . Still highly economic with 95mbo breakeven. We still think artificial lift will be key to improve EURs."); *see also* AMR_SDTX00665836 at -5848 (Alta Mesa slide deck, "First Quarter 2018 Operational Update," May 14, 2018).

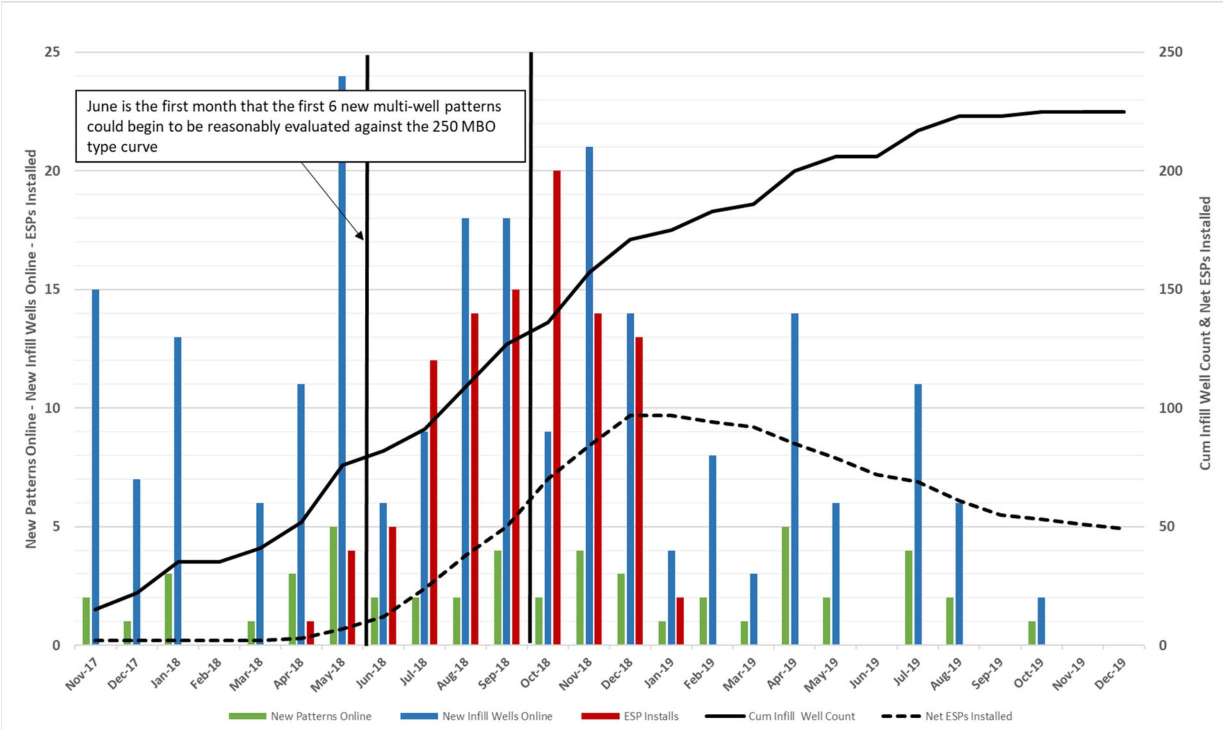

Figure 23 – Data in Figure 22 with ESP Installations

7. Alta Mesa Reasonably Determined the Optimum Well Count for Drilling Units Once They Obtained Sufficient Production Data

From my review and analysis, as set forth above, it is clear that Alta Mesa acted reasonably once it had sufficient well-production data—both to understand the nature of their wells' underperformance and to adjust their well-spacing accordingly. Following receipt in June 2018 of results from its first six multi-well patterns and installation of ESPs, Alta Mesa's ongoing analysis of its multi-well patterns showed that three- and four-well patterns (well spacing of 1500-feet in-bench well spacing) were performing best, as reflected in a September 2018 Board of Directors meeting presentation.[47] Subsequently, Alta Mesa reduced infill well count starting in October of 2018, as shown in **Figures 18** and **20**. The reduced well count is shown in **Figure 24,** which includes the same data shown on **Figure 23**, plus the average number of infill wells per pattern. The average per-pattern infill well count is depicted as black dots. Details for each pattern are shown in **Table 5.**

[47] *See* September 18, 2018 Board of Directors Meeting, Meridian_000000750, slides 194-195.

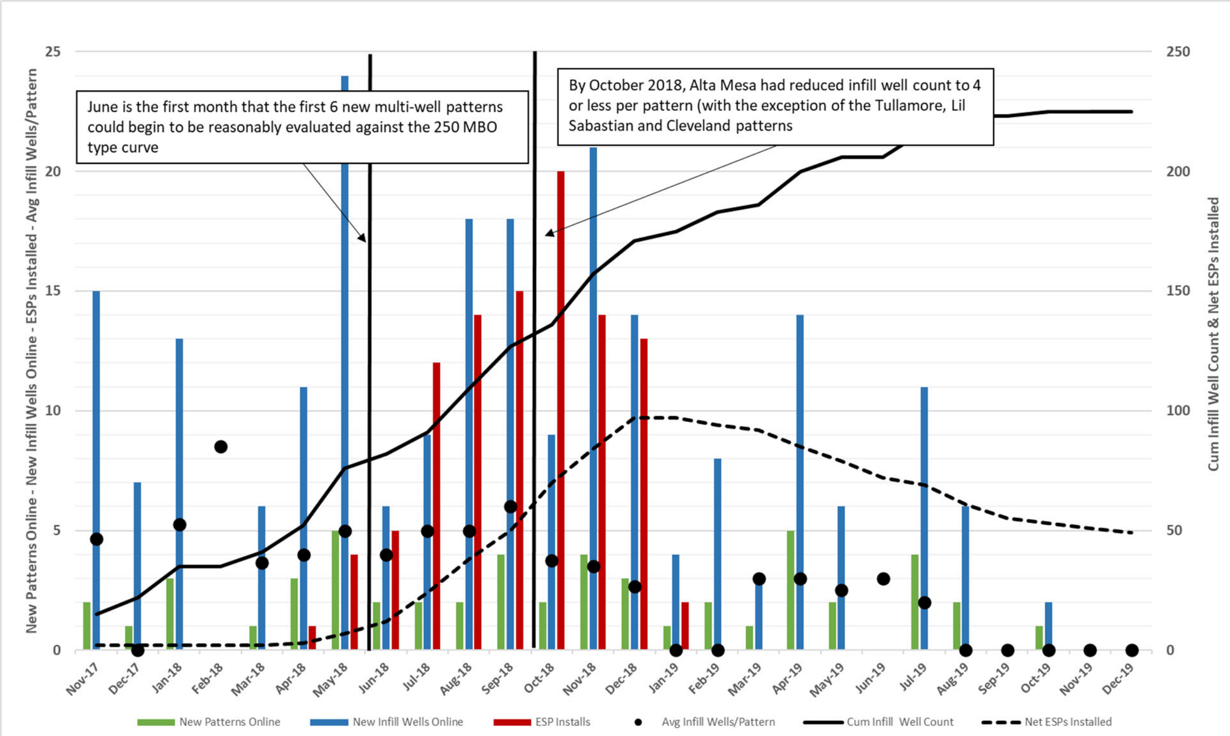

Figure 22 – Data in Figure 23 with Average Infills Per Pattern & Key Dates Added

Table 5 – Key Dates and Well Types for Alta Mesa's Multi-Well Development Patterns[48]

PATTERN	FIRST SPUD DATE	FIRST PRODUCTION DATE	DELTA	FIRST ASSESSMENT DATE	PARENT COUNT	SIBLING COUNT	INFILL PARENT COUNT	CHILD COUNT	TOTAL WELL COUNT
Ash-Foster	5/14/2017	11/4/2017	174	3/4/2018	2		1	7	10
Hoskins	6/9/2017	12/17/2017	191	4/16/2018	1		2	5	8
Themer	6/22/2017	11/28/2017	159	3/28/2018	1		3	4	8
Paris	8/9/2017	1/4/2018	148	5/4/2018	1		1	4	6
Todd	8/18/2017	1/22/2018	157	5/22/2018	1			3	4
Lankard	9/12/2017	1/18/2018	128	5/18/2018	1			5	6
James	10/13/2017	4/22/2018	191	8/20/2018	1			3	4
Zeppelin	11/3/2017	4/5/2018	153	8/3/2018	0		1	3	4
The Trick	11/16/2017	3/22/2018	126	7/20/2018	1		2	4	7
Niko	11/29/2017	4/16/2018	138	8/14/2018		4			4
Odie	1/1/2018	5/18/2018	137	9/15/2018	1		1	5	7
Red Queen	1/13/2018	5/25/2018	132	9/22/2018	1			3	4
Huntsman Old Crab	1/19/2018	5/31/2018	132	9/28/2018	1		4	5	10
Oak Tree	1/28/2018	5/4/2018	96	9/1/2018	1			3	4
SE-Slaughter House	2/18/2018	8/14/2018	177	12/12/2018			12	2	14
Speyside	2/26/2018	5/16/2018	79	9/13/2018	1			3	4
Peat	3/5/2018	6/17/2018	104	10/15/2018	1			3	4
Greene-Mackey	3/13/2018	7/2/2018	111	10/30/2018	1			5	6
Sawgrass	3/15/2018	6/25/2018	102	10/23/2018	1			3	4
Slugworth	4/20/2018	7/30/2018	101	11/27/2018	1			4	5
Whiskeyfeet	5/4/2018	8/28/2018	116	12/26/2018		4			4
Redbreast	5/12/2018	9/23/2018	134	1/21/2019	1			6	7
Daydrinker	6/5/2018	9/1/2018	88	12/30/2018	1			3	4
Walrus	6/11/2018	9/30/2018	111	1/28/2019	1			6	7
White King	6/14/2018	9/28/2018	106	1/26/2019	1			3	4
Dalwhinnie	7/4/2018	10/22/2018	110	2/19/2019	1		2	1	4
Mad Hatter	7/4/2018	10/27/2018	115	2/24/2019	1			6	7
White Rabbit	7/17/2018	11/2/2018	108	3/2/2019	1		2	4	7
Bollenbach - sec 21	8/3/2018	11/19/2018	108	3/19/2019			3	4	7
Boecher	8/29/2018	11/17/2018	80	3/17/2019	1			3	4
Cheshire Cat	8/31/2018	11/24/2018	85	3/24/2019	1		1	4	6
Fazio	9/3/2018	12/15/2018	103	4/14/2019	1		1	5	7
Bollenbach - sec 27	10/8/2018	12/8/2018	61	4/7/2019	1			2	3
Tullamore	10/10/2018	12/24/2018	75	4/23/2019	1			6	7
Lil Sebastian	10/14/2018	1/18/2019	96	5/18/2019	1			4	5
Sadiebug	10/31/2018	2/20/2019	112	6/20/2019	1			3	4
Evelyn	11/1/2018	4/4/2019	154	8/2/2019	1			3	4
Cleveland	11/10/2018	2/26/2019	108	6/26/2019	1		1	4	6
Towne	11/17/2018	3/29/2019	132	7/27/2019	1			3	4
EHU 255/257/259	11/17/2018	4/23/2019	157	8/21/2019		3			3
EHU 252/254/256/258	12/3/2018	4/13/2019	131	8/11/2019		4			4
Kilgore	12/19/2018	4/12/2019	114	8/10/2019	2			2	4
Helen	12/19/2018	4/12/2019	114	8/10/2019	1		1	1	3
Edwin	3/1/2019	5/11/2019	71	9/8/2019	1			3	4
Aberfeldy	3/2/2019	5/10/2019	69	9/7/2019	1			3	4
Mouse Rat	4/9/2019	7/3/2019	85	10/31/2019	1			3	4
Bunker Buster	4/11/2019	7/11/2019	91	11/8/2019	1			3	4
Aces High	5/16/2019	7/25/2019	70	11/22/2019	1			2	3
Mayes-Schilde	5/21/2019	7/26/2019	66	11/23/2019	2			3	5
Wakeman	6/13/2019	8/30/2019	78	12/28/2019	1			3	4
Brown	6/20/2019	8/22/2019	63	12/20/2019	1			3	4
Hasley	7/24/2019	10/25/2019	93	2/22/2020	1			2	3

[48] For purposes of this report, a "parent well" is defined as a well drilled with no previous horizontal Mississippian production within a drainage area of 2,640 feet (2 well-per-section ("WPS") spacing) in both the east and west perpendicular direction from the wellbore. Using the same drainage area assumption, a "child well" is defined as a new well that has had previous horizontal Mississippian production more than 90 days before the production of the new well within the assumed drainage area. An "infill parent well" is defined as a new well that is part of a multi-well development pattern that contains children wells, but it is not a child well since it is not

8. Alta Mesa's Efforts to Improve Well Recovery and Reduce Costs Were Reasonable and Consistent with Industry Practice

Alta Mesa also took steps to improve well recovery. Two examples of these efforts were:

- *Drilling S-shaped wellbores in an effort to improve per-well recovery.* An illustration of the incremental reserve potential from an S-shaped well's added completion length is shown below. For this analysis, I reviewed all of Alta Mesa's horizontal Mississippian wells in Kingfisher County, recorded the lateral length of each well, and noted which of the wells were S-shaped. Of the 431 Alta Mesa Mississippian horizontal wells in the dataset, the average lateral length of the S-shaped wells was 155 feet longer than the average lateral length of wells with non-S-shaped designs.

  Illustration:
  - *Total AMR horizontal wells: 431*
  - *Total S – shaped wells: 222 with an average lateral length of 4,800 ft*
  - *Total non-S-shaped wells: 209 with an average lateral length of 4,645 ft*
  - *Difference: 155 ft*

$$Total\ well\ oil\ reserves = 250{,}000\ barrels$$
$$Lateral\ length\ of\ a\ non\text{-}S\text{-}shaped\ well = 4{,}645\ ft$$
$$Reserves\ per\ foot\ = \frac{250{,}000\ barrels}{4{,}645\ feet} = 53.8\ \frac{bbls}{ft}$$

$$Incremental\ footage\ completed\ with\ an\ S - shaped\ well\ = 155\ feet$$
$$Incremental\ Reserve\ Potential = 53.8\ \frac{bbls}{ft}\ x\ 155\ feet = 8{,}339\ barrels$$
$$Potential\ value\ at\ \$50/bbl = \$416{,}950$$

- *Continuously studying various frac designs and their impact on well drilling and completion costs and ultimate reserve recovery.* These efforts involved:

  - Developing best practices in the normally pressured, naturally fractured oil window of the STACK;

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within the defined drainage area of a parent well. These could be defined as child wells as their spacing is that of the adjacent child wells drilled at the same time. The distinction is an effort to understand the distance of each child well relative to a parent well, either in the named pattern or an adjacent pattern. "Sibling wells" are a sub-classification of parent wells, and they are defined as parent wells that are part of a multi-well development that were completed and started production at the same time.

- Investigating methods for reducing frac hits on existing wells, *e.g.*, loading the existing well with water prior to fracing a child well;

- Changing the length of a frac stage, the volumes of proppant (*i.e.*, sand) and fluid pumped per stage, and various completion equipment methods as Alta Mesa progressed from frac generation 1 through frac generation 2.5+. These differences were measured by reviewing the per-well EUR and noting its frac generation.[49]

Other evidence that Alta Mesa was keeping pace with the industry to gain overall completion efficiency in their STACK acreage was the Company's use of:

- Walking-type rigs to allow for more efficient and cost-effective rig movement when drilling multiple wells from a single surface pad;

- A "zippering" technique for fracing wells, to take advantage of increased frac fleet utilization when fracture stimulating multiple wells from a single surface pad;[50]

- Tracking execution, by calendar quarter, of the number of frac stages that could be completed per day for both single well pads and multi-well pads; and

- Investigating various sand-sourcing options to reduce transportation costs.[51]

C. Alta Mesa's Use of Electric Submersible Pumps was Reasonable from an Operational Perspective

1. Artificial Lift Methods Used by Alta Mesa

As initial production begins, use of artificial lift is necessary to efficiently "clean up" wells and achieve maximum production rates. For these reasons, artificial lift is evaluated first when a well is performing below expectations. Although pre-drill predictions (such as those reflected in a type curve) assume an efficient artificial lift system, inefficient artificial lift can significantly reduce production rates and lead to erroneous conclusions. Fortunately, an artificial lift system can be quickly modified in a well.

Alta Mesa used gas lift, ESPs, jet pump, plunger lift, and—on a very limited basis—rod lift. The Company made assessments of which artificial-lift method should be deployed in each well, depending on the well's producing characteristics. As is standard in the industry, for new wells, Alta Mesa utilized gas lift, ESPs, and jet pump. Later in a well's life, Alta Mesa continued to use gas lift and plunger lift.

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[49] *See generally* Meridian_000000750, slides 141-160.

[50] *See id.,* slides 141, 162.

[51] *See id.,* slide 165.

Table 6 provides a breakdown of the artificial lift installed in the 446 horizontal wells that Alta Mesa operated in Oklahoma as of December 10, 2019, the last date for which such information is available.

Table 6 – Types of Artificial Lift Alta Mesa Used

Lift Type	Well Count	%
Gas Lift	352	79%
ESP	49	11%
Jet Pump	3	1%
Plunger Lift	32	7%
Rod Pump	4	1%
Unknown	6	1%
Total Wells	446	

As shown in **Table 6**, Alta Mesa used ESPs in 11% of its wells over a long period. At a high point, the Company used ESPs in a total of 102 wells (23% of total wells).

2. Alta Mesa Had a Valid Basis for Its Use of ESPs

Based on my experience with all types of artificial lift (including ESPs) and my detailed analysis, summarized below, Alta Mesa's use of ESPs was reasonable in light of the circumstances it encountered. The Company's use of ESPs was also well within industry norms.[52]

As shown in both **Figure 24** (above) and **Figure 25**, below, Alta Mesa began to install more ESPs in May 2018, and it continued installations through January 2019. It ultimately installed a total of 102 ESPs, mostly between July and December 2018.

[52] A paper published in 2020 by the SPE noted: "In the present day scenario, approximately 40% of the unconventional wells that are installed with [artificial lift] systems employ Gas Lift (GL), 36% resort to Electrical Submersible Pumps (ESPs), 13% employ Sucker Rod Pumps (SRPs), 7% use Plunger Lift (PL) while Jet Pumps (JETs) are employed in 4% of these wells." SPE Paper No. 201692 MS (2020), *A Comprehensive Review and Optimization of Artificial Lift Methods in Unconventionals. These values represent statistics in the United States.*

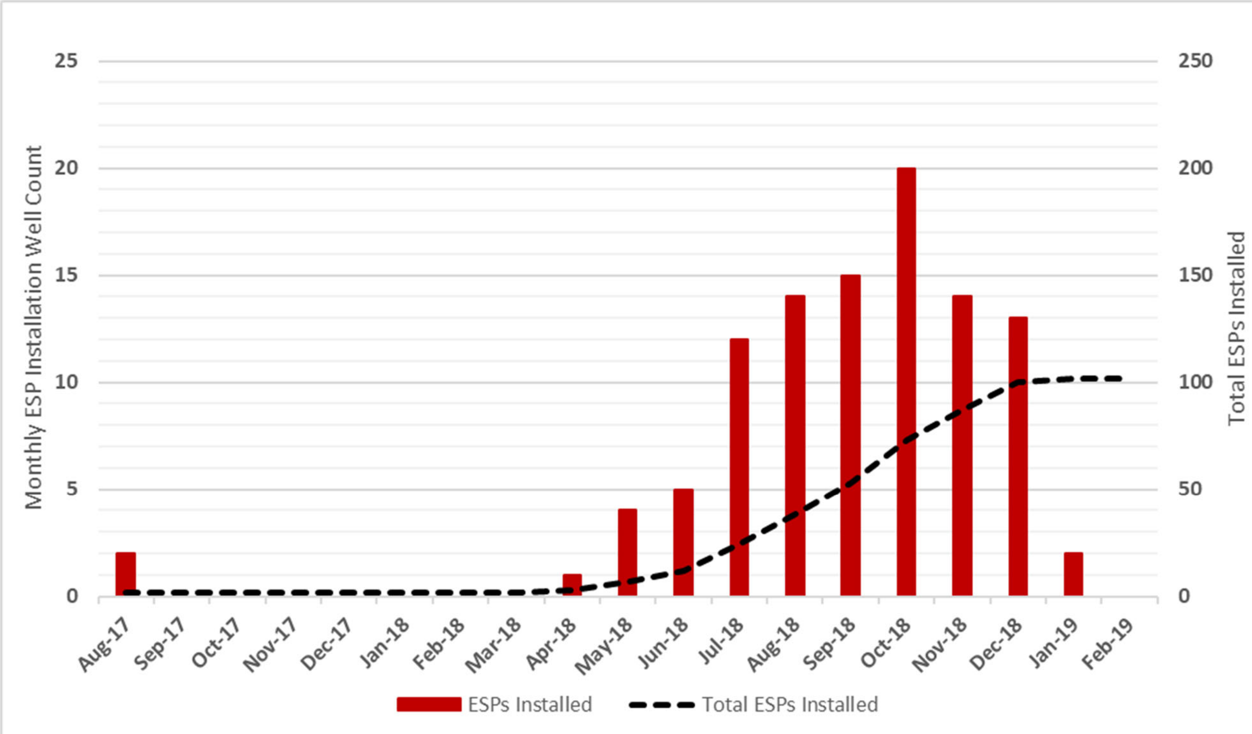

Figure 25 – ESP Installation Dates

Production plots for each Alta Mesa well show that ESPs were installed in three situations: (1) in a new well; (2) in an existing well to mitigate the effects of a frac-hit from one or more offset wells; and (3) in an existing well to increase total production rates. Production plots showing use of ESPs in each of these situations are reproduced in **Figures 26–28**, respectively.[53]

[53] Appendix F contains production plots for all 102 wells in which Alta Mesa installed ESPs.

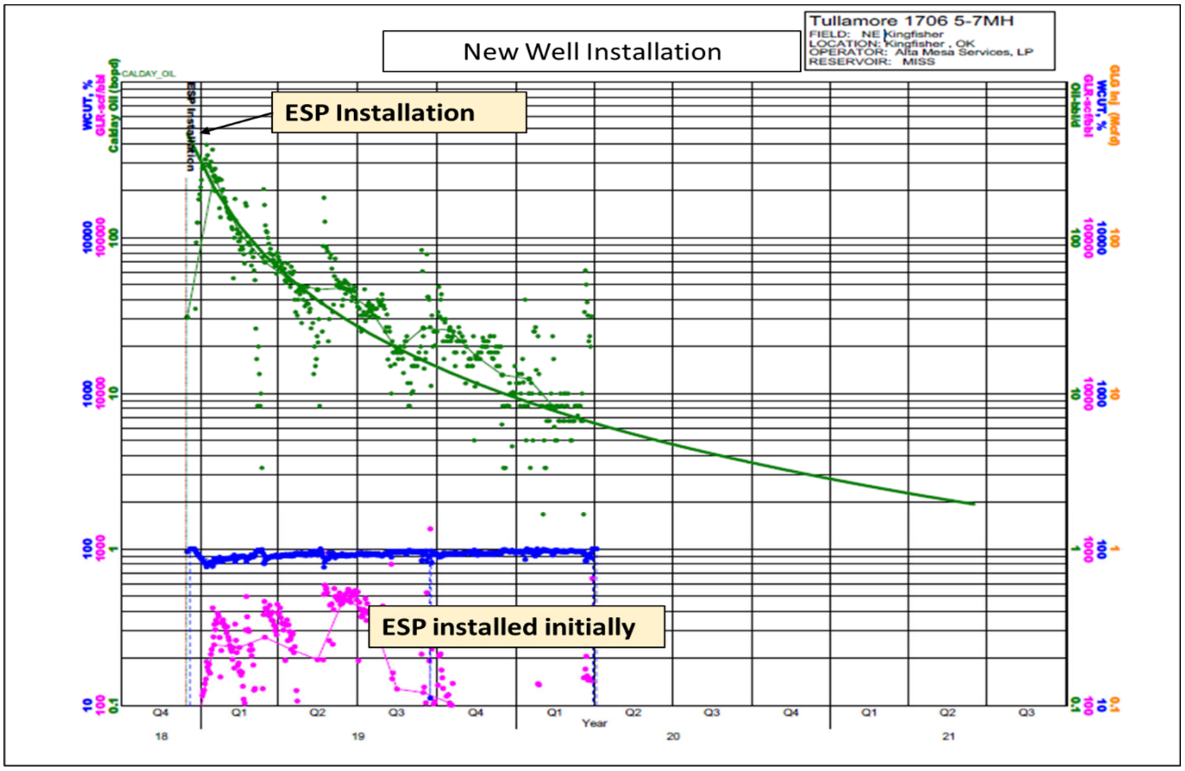

Figure 26 – Example of an ESP Installed in a New Well

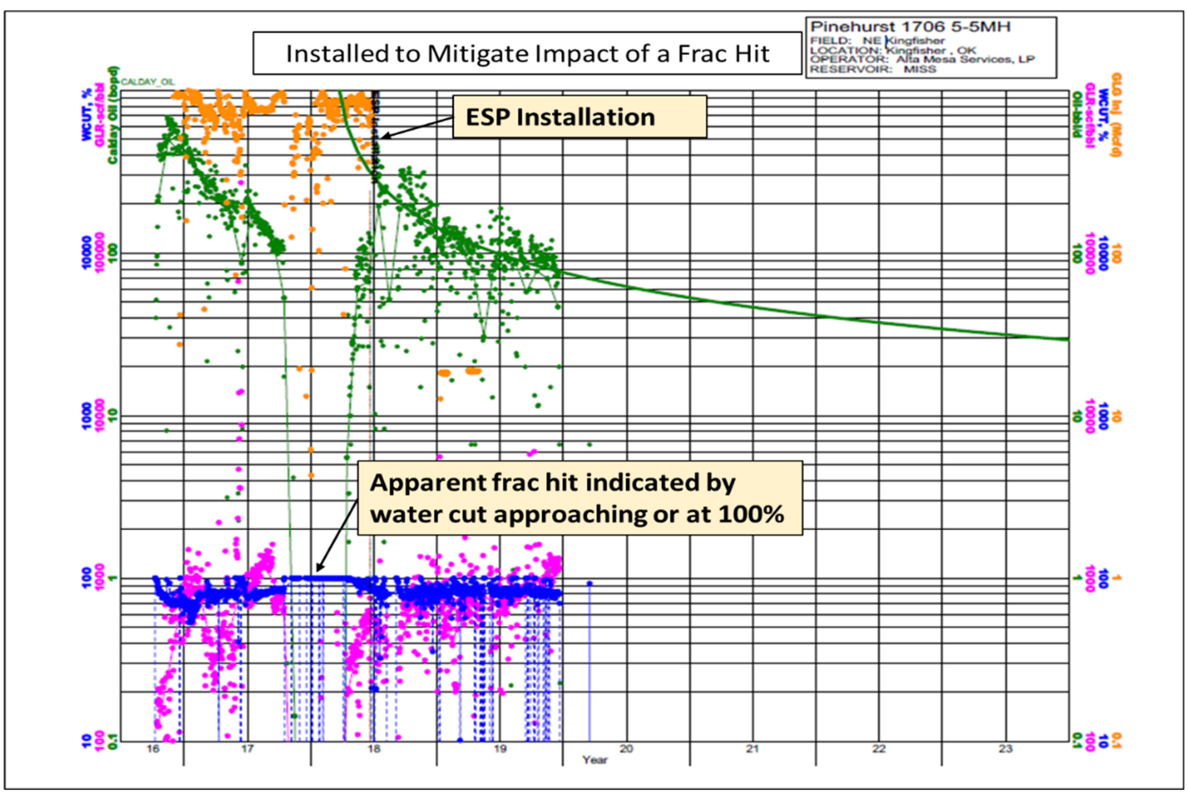

Figure 27– Example of an ESP Installed in a Well Hit by an Offset Well Frac

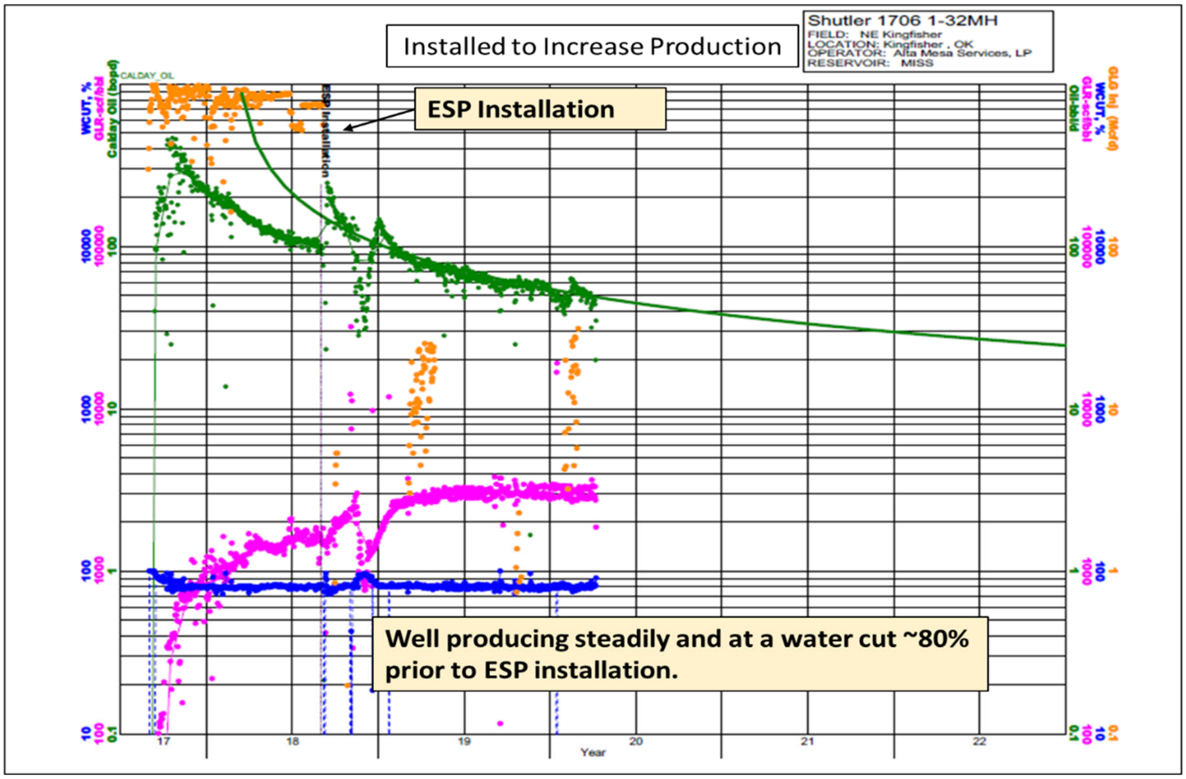

Figure 28 – Example of an ESP Installed in a Well to Increase Production Rates

A summary of the reasons ESPs were installed, and the wells' responses to those installations, is provided in **Table 7** below. I judged the effectiveness of a response as "good," "moderate," or "poor" based on my approximation of each well's production rates before and after the ESP installation.[54]

[54] Appendix F includes a summary table of my analysis of each well's performance before and after ESP installation.

Table 7 – ESP Use Summary

ESP Installation Reason	Well Response	Number of Wells	% of Wells
Frac Hit		37	36%
Improve Production		45	44%
New Well Installation		20	20%
Total All Reasons		102	100%
Frac Hit	Good Response	37	100%
37	Moderate Response	0	0%
	Poor Response	0	0%
		37	100%
Improve Production	Good Response	21	47%
45	Moderate Response	13	29%
	Poor Response	11	24%
		45	100%

Frac-hit wells: Alta Mesa installed ESPs in a total of 37 wells (36% of total ESP installations) that were frac-hit by offset well(s). ESPs were installed after the hydrocarbon production from those wells either ceased entirely or significantly declined, causing the produced water (*i.e.*, "water cut") to approach or equal 100% of the fluids produced by the well. In some of those wells, Alta Mesa first attempted, unsuccessfully, to use gas lift to remove the water.

In **Table 7** above, I rated a well's response to ESP installation as "good" if the well was able to resume production at, or near, its pre-frac-hit production rate. Of the frac-hit wells, all had a good response, with production being restored to pre-frac-hit rates or better over a relatively short period of time. In this application, Alta Mesa's results were the best I have seen. In my experience, frac-hit wells more often than not either never return to their pre-frac-hit production rates, or return to that level only gradually over a lengthy period.

Increased production: Alta Mesa installed ESPs in a total of 45 wells (44% of installations) to increase production rates. Seventy-six percent of those installations had a good to moderate response.

By December 2019, Alta Mesa had removed ESPs from all but 49 wells. *See* **Figure 29**. For many wells in which ESPs were installed and then removed, the ESP had done its job by removing fracture-stimulation fluids or by accelerating the well's production to a point where another form of lift, usually gas lift, was more economical.

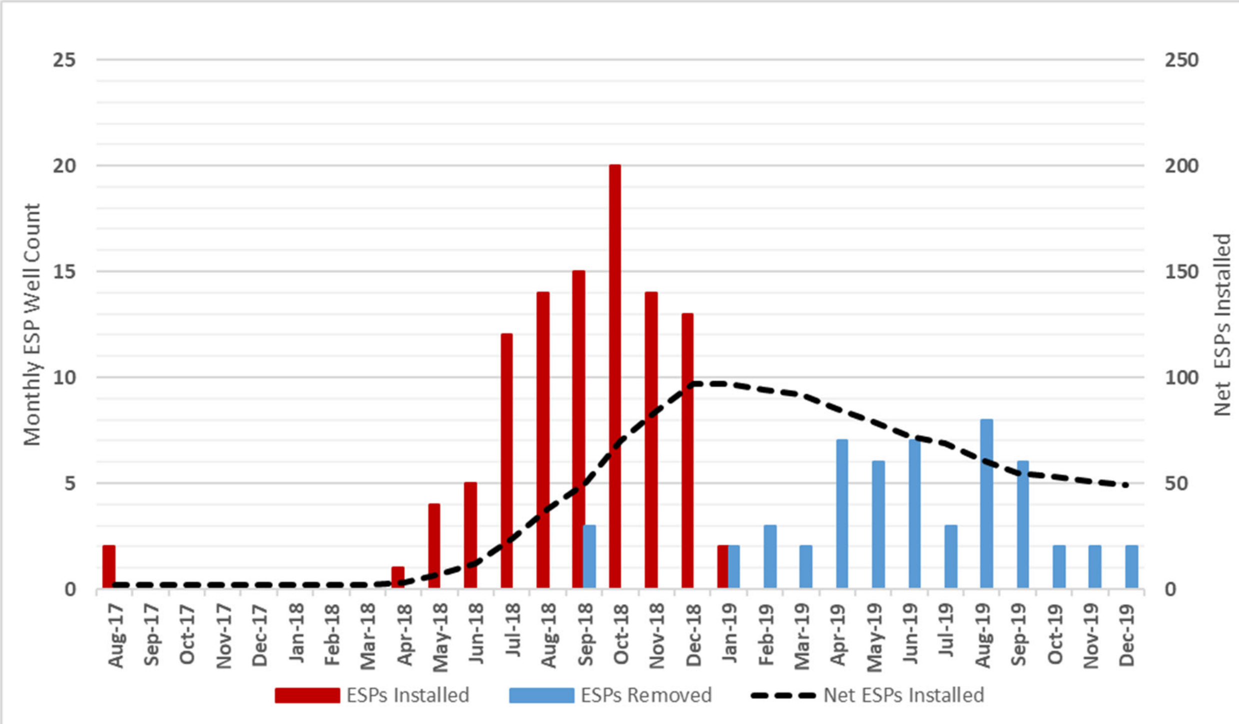

Figure 29 – ESP Install and Removal Dates

In sum, Alta Mesa's use of ESPs was reasonable when assessed in light of the circumstances the Company faced when it began increasing its use of ESPs in May 2018. At that time, Alta Mesa was still in the relatively early stages of developing its acreage. All efforts were properly focused toward ascertaining the true performance of the wells as quickly as reasonably possible. Specifically, Alta Mesa:

- Successfully restored production of frac-hit wells to pre-frac-hit production trends;
- Ensured that wells were producing without being hindered by a poor-performing artificial lift method; and
- Began replacing ESPs when equipment failed with other, then-competitive forms of artificial lift, usually gas lift.

In addition, Alta Mesa's use of ESPs was an important factor in identifying their well-performance problems as well-to-well interference, *i.e.*, too many wells per section, so that spacing adjustments could be made as soon as practical.

D. <u>Alta Mesa's Use of ESPs Did Not Negatively Impact Overall Ultimate Reserve Recovery</u>

Despite claims to the contrary, Alta Mesa's use of ESPs did not have a negative impact on the ultimate recovery of oil from their leases. One way to assess the validity of that claim is to

monitor a well's Gas-Oil Ratio ("GOR") at different bottomhole flowing pressures over a relatively short period of time. Under normal pressure decline, the GOR will steadily increase in a smooth and monotonic fashion, as shown in **Figure 30**. If, at a suddenly lower bottomhole flowing pressure, the GOR increases and stays at that level after the bottomhole flowing pressure is increased, it is *possible* that some oil will be stranded, resulting in lower ultimate oil recovery from the well.

I used that test to evaluate the GOR behavior of each of the 102 wells in which Alta Mesa installed an ESP to determine: (1) whether a well's GOR trend showed a normal increase in light of its bottomhole flowing pressure, as shown in **Figure 30**, or a larger increase; and (2) whether there was a significant change in a well's GOR associated with a change in artificial lift method. The results of my study are set forth in Appendix G. As shown there, only five of the 102 wells experienced a larger-than-normal GOR increase after the installation of an ESP. From that evidence, I conclude that the ESPs did not negatively impact overall ultimate oil recovery from the wells where they were installed.

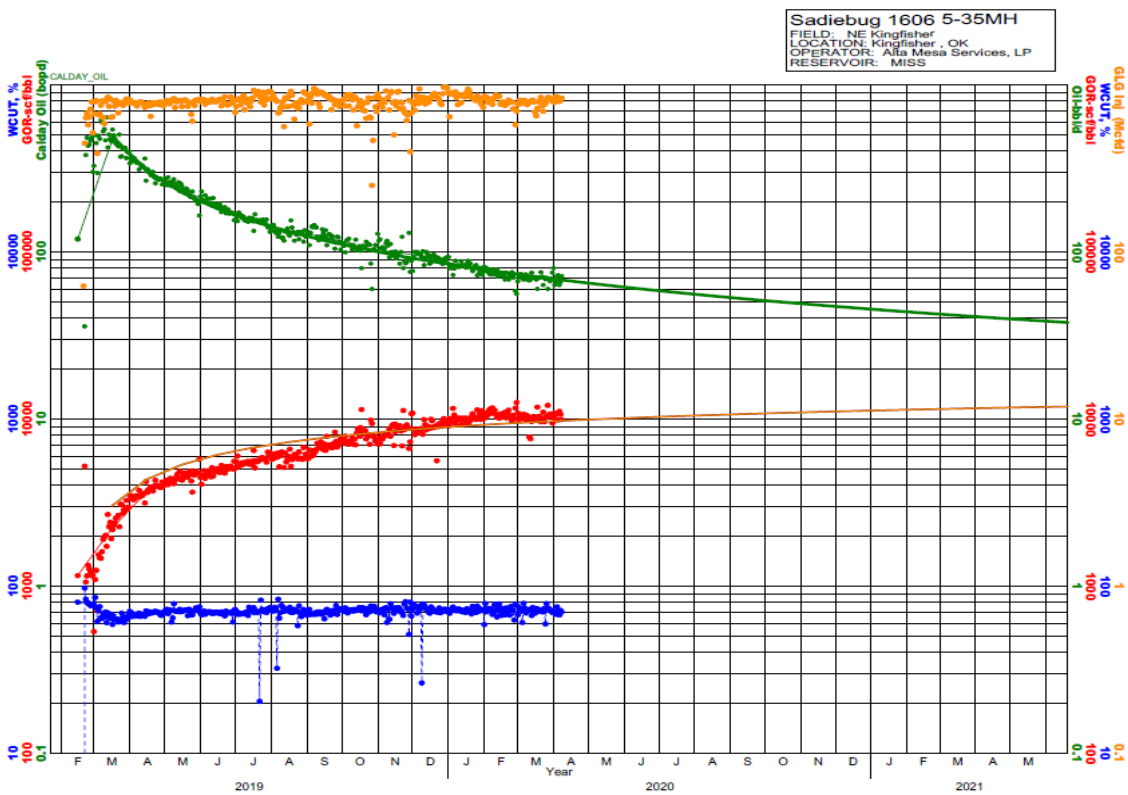

Figure 30 – Example of a Producing Well GOR Profile

E. Alta Mesa's Drilling of Deviated Wellbores Was in Line with Other STACK Operators

Alta Mesa's drilling of deviated wellbores was in line with other STACK horizontal-well operators in Kingfisher County, as many of them drilled wells exceeding a DLS of 5 degrees. A total of 28 operators drilled horizontal Mississippian wellbores in the STACK between 2012 and

2022. Twenty-one of these operators drilled wellbores having a DLS exceeding 5 degrees. **Figure 31** shows these 21 STACK operators and the percentage of their wells that exceed a DLS of 5 degrees in each year[55] Thus, Alta Mesa's practice with deviated wellbores was not excessive when compared to their peers in the area.

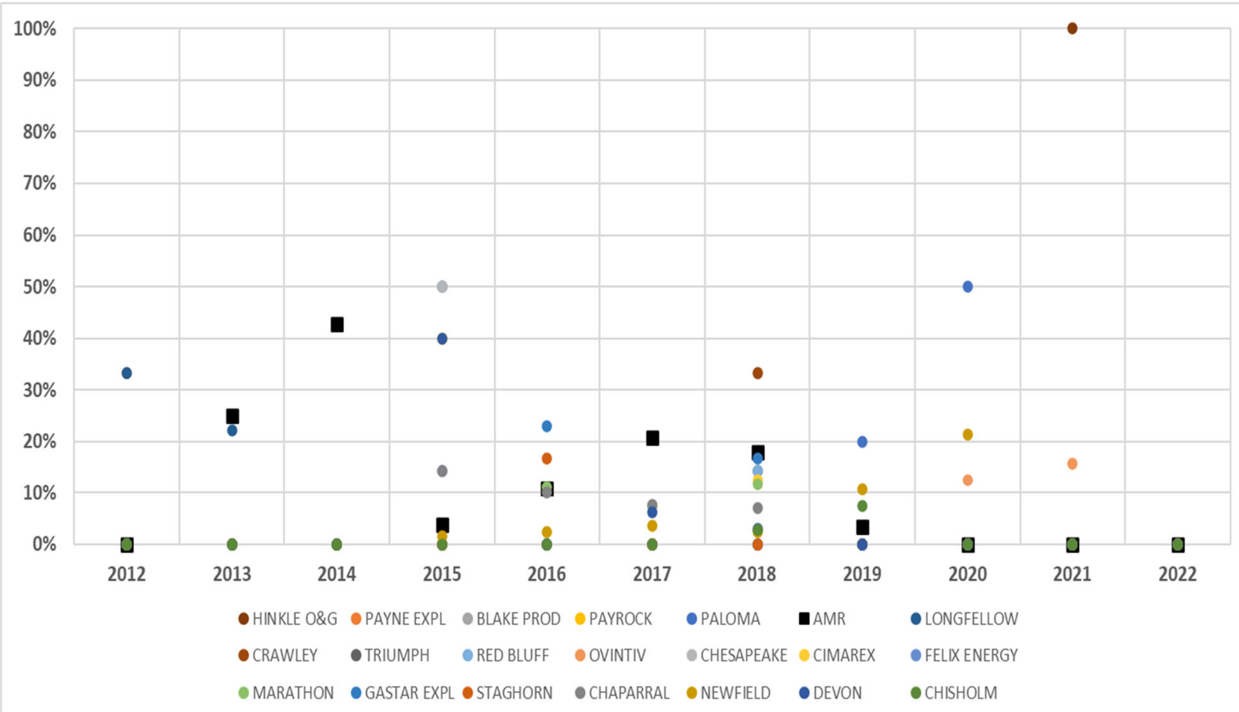

Figure 31 – Percentage of Horizontal Mississippian Wells Drilled with a DLS > 5 Degrees by Operator in Kingfisher County

Figure 32 shows the total horizontal wells drilled by these 21 operators and the percentage of their wells that exceed a DLS of 5 degrees. Again, Alta Mesa is consistent with their peers with 73 (17%) of their total wells having a DLS greater than 5 degrees.

[55] Note that the DLS values were calculated from the surface to 1000 feet true vertical depth above the well's maximum true vertical depth. This was done to avoid including in the DLS calculation the curve leading to the lateral in the reservoir.

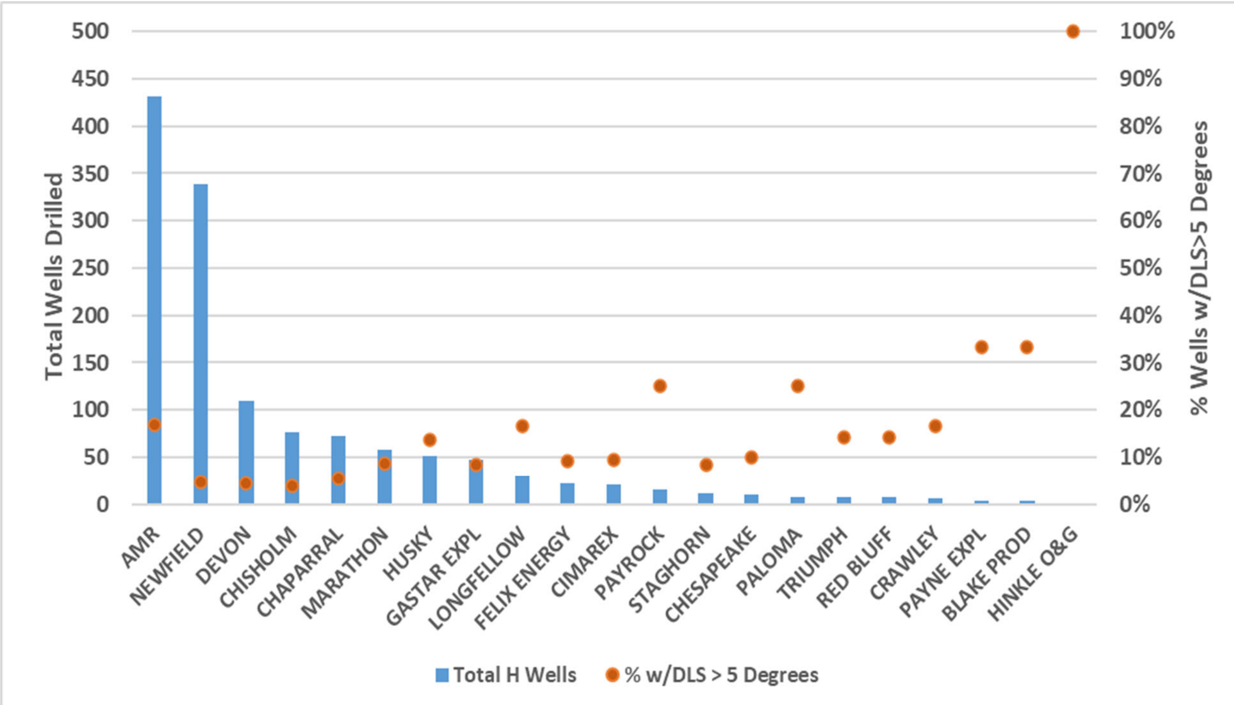

Figure 32 – Overall Horizontal Mississippian Well Count and Percentage of Total Wells Drilled with a DLS > 5 Degrees by Operator

Alta Mesa's drilling of wells with deviated wellbores was not detrimental to a well's ultimate recovery because it allegedly precluded use of rod lift later in the well's life. As previously discussed, deviated wellbores are a fundamental element of unconventional reservoir development. Some sources suggest that rod lift should not be used in wells with DLS greater than 5 degrees. However, wells with a DLS greater than 5 degrees have been pumped successfully with rod lift.[56] Wells with DLS greater than 5 degrees should be modeled with appropriate software and in conjunction with rod lift equipment suppliers.[57]

The important point here is that deviated wellbores exceeding 5 degrees are common in the STACK, as reflected in **Figures 31** and **32**; and until one performs a well-by-well analysis of each of those wells, whether rod lift can be used for artificial lift cannot be known. I have seen no evidence that rod lift is used routinely in STACK wells. In fact, during my many visits to the field through 2021 when I was at Cimarex, I did not see rod lift being used in most wells in the STACK. I know that Cimarex did not use rod lift in their STACK wells. More commonly, Cimarex used gas lift and later transitioned to plunger lift.

Plunger lift can be used with the aid of gas lift, known as gas assisted plunger lift ("GAPL"), or alone using only gas native to the formation, known as conventional plunger lift. GAPL is often used as an intermediate step between gas lift and conventional plunger lift. Eighty

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[56] *See* note 16, *supra.*

[57] *See* Lea, James F., Rowlan, Lynn, "Use of Beam Pumps to Deliquefy Gas Wells, Gas Well Deliquification" (Third Edition), 2019; *see also* footnote 14, *supra.*

percent (80%) of Alta Mesa's wells were being gas lifted in December 2019, so GAPL was a viable option for wells with DLS greater than 5 degrees.[58]

I evaluated the 74 Alta Mesa wells that have a DLS greater than 5 degrees, using criteria for conventional plunger lift viability described in a paper published in 2020 by the SPE and referenced above.[59] Production plots for those wells, including the threshold criteria, are shown in Appendix H. Each well was evaluated first to determine if its producing GLR exceeded the criteria, and second to test if its forecasted GLR from the forecasted oil, gas, and water rates exceeded the criteria. The results are shown in **Table 8**.

Table 8 – Plunger Lift Potential Through April 2020

Well Can Be Plunger Lifted		
Yes	**Borderline**	**No**
41%	9%	50%

From this analysis, I concluded that 30 of the 74 wells (41%) having DLS greater than 5 degrees could be artificially lifted with conventional plunger lift. The 37 wells (50%) that did not meet the criteria for plunger lift could be produced with GAPL, or evaluated more critically for possible use of rod lift, as noted in footnote 18. Plunger lift could be attempted in the 7 wells (9%) listed as "Borderline" to see how they perform.

V. CONCLUSION

For all the reasons stated above, I find that Alta Mesa's development of its STACK acreage was reasonable from an operational and technical perspective given the information they had when decisions were made.

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[58] GAPL requires less gas to lift the well than conventional gas lift, which lowers operating costs. GAPL's advantage is that it can produce more fluid than conventional plunger lift. As depletion continues, conventional plunger lift is typically used as the final lift method unless the formation is not producing enough gas to compensate for the fluid rates, leading to a gas-to-liquid ratio ("GLR") that is too low.

[59] *See* note 46, *supra*. There are two criteria. First, the well must produce at a GLR that is greater than or equal to 400 standard cubic feet per barrel of total fluid, multiplied by the vertical distance in thousands of feet to the maximum recommended plunger set depth of 45 degrees wellbore deviation. Second, the well must be producing at a total fluid rate less than 200 barrels per day.

EXHIBIT B

UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

IN RE ALTA MESA RESOURCES,) CASE NO.
INC. SECURITIES LITIGATION) 4:19-cv-00957

REMOTE VIDEOTAPED DEPOSITION OF
EDWARD FETKOVICH
NOVEMBER 1, 2023
9:03 a.m. ET

Witness Appearing From:
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Washington, D.C. 20004

Conducted Remotely Via Videoconference

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Entwistle & Cappucci

Mr. Gus Phillips - Videographer

A. For the improved production, yes.
Q. Okay. And then so that's 36 frac-hit wells, 45 improved production wells. And as we've discussed, there's no analysis on the 21 new well installations, correct?
A. Correct.
Q. Okay. And the results that are shown in this -- this little bulleted summary, that's based on -- the costs in that are based on the AFEs? Is that correct?
A. That is correct. It's based on the AFEs.
Q. Are you aware of testimony in this case that -- or any evidence in this case that Alta Mesa understated certain costs in some of their AFEs?
MS. GRAGERT: Objection.
A. I'm not aware. I'm not aware of that.
Q. Do you know whether the AFEs would include the operating costs of the ESPs, including electricity?
A. No, the AFEs would not. That would have been in the ARIES economics case.
Q. And did you -- did you -- so when you say you based it on the AFE, did you take that number of the AFE and then did you add the cost of electricity on top of that?

A. No. So what happened is the cost to install is a capital cost. Okay? That's an up-front capital cost. The cost to operate is an operating cost that's -- that's different.

What we did, because Alta Mesa did not provide significant detail on well-by-well-by-well operating costs, we used the ARIES economics database was -- that -- and the way they were set up at the end of 2017. And what they had in there was a average cost to operate a well. Okay? And so what we did was we assumed that that operating cost would be in force or in effect had the well remained on gas lift.

When -- for the case where -- for the part of the case that assumed the ESP install, we doubled that cost. And we felt like that was actually probably really conservative, on the high side, to double the -- to just take that cost and double it. It should have been more like 50 percent, but we felt like that was a reasonable thing to do.

So to understand the way we ran the economics, if we had a well that was on improved production, we saw how it was trending before the ESP was installed; we forecasted that production to get a base case. We had those -- we had those

operating costs I just mentioned. That would be like the negative one case in ARIES. And then for the positive one case, we had the capital cost to install the -- to install the ESP.

And then the production history for that install was the production history, right? We didn't do anything to finesse that. It was the production history. And the economic case lasted for as long as the ESP was installed.

If the ESP was never removed, then we simply ran the case to the end of the available data that we had, which was the February of 2020. And that's how we ran it.

MS. GRAGERT: Counsel, you've got about 30 minutes left.

MR. BRODEUR: Well, I'm not sure about that, but it should be enough.

Q. The -- did you -- did you project incremental oil production out for the life of the wells if the ESP was not removed?

A. No. We stopped -- if the ESP was not removed, we just -- we stopped at the ca- -- at the end of available history, which for us was February of 2020.

Q. Let's go to Appendix A of your rebuttal

report.

A. Okay. I'm there.

Q. Okay. And then there are several -- is this your economic anal- -- does Appendix A refer to your economic analysis of ESPs?

A. Yes, it does.

Q. Okay. And then the last page of Appendix A, so it's stamped 33, there's a -- there's sort of a full-page chart, correct?

A. Yes.

Q. Okay. And this is sort of a summary of your economic analysis? Is that true?

A. That is true.

Q. Who prepared this chart?

A. Connor Riseden --

Q. Okay.

A. -- with Netherland Sewell.

(Reporter Clarification)

A. He's with -- he's the one with Netherland and Sewell.

Q. Got it. Did he prepare it at your direction?

A. He did.

Q. Was it prepared in Microsoft Excel?

A. No, it was done with -- well, the economic

analysis was done in ARIES and the results were summarized in this Microsoft Excel spreadsheet.
Q. The results were exported to the spreadsheet?
A. Yes.
Q. So the calculations were performed in ARIES?
A. In ARIES, that's correct.
Q. Did you work with the Excel document at all, or did you put it into your report as Mr. Riseden provided it to you?
A. No, I looked over the results. I created the summation at the bottom for the -- the base case, which is the fourth column from the right, and I generated the summation of the sensitivity capital cost case in the last column to the right. And other than that, that is all that I did.
Q. What is a -- so is the difference between the base case and the capex sensitivity case, is the only difference that you used AFEs for the base case and the 453 number for the capex sensitivity case?
A. Yeah. So what we did was trying to cover the cost, we had the AFEs and any supplements that went into the base case. We also noted that Alta Mesa used something called an AFE tracking

database.

Q. Yeah.

A. And in there, there were a number of entries, that ESP in general, 453,000. We saw that for the most part that was higher than what we saw on average from the base case, but we thought that that would be a good idea to run that as a sensitivity. That's -- that's -- that's the -- that's the difference. It was just trying to look at a cost sensitivity.

Q. And is -- is "base case" a term that you're familiar with from your experience working in the oil industry?

A. It is.

Q. And generally speaking, what is a base case?

A. The base case in this -- in this context would be the information that we found that was directly applicable to the well. It wasn't a hypothetical. Like the 453,000 was a hypothetical that we just applied across the board. In this instance the base case was the actual cost that we found through the AFEs and the supplements.

MR. BRODEUR: And -- Faith, could I have Tab 41, please, in the -- in native.

Q. While that's loading, let me ask you, did you look -- did you review any economic analysis performed by Alta Mesa in 2018 regarding its ESP program?

A. I did not, no.

Q. Do you know if Alta Mesa did an economic analysis related to its ESP program?

A. It's a good question. I believe that I've seen -- I've seen a spreadsheet that showed that they did do an economic analysis. I couldn't give you the Bates number on that. I did see an analysis that they had done that looked like it was ARIES exported type of information that was in a spreadsheet. So it looked to me like they had.

Q. As between you and the folks at Alta Mesa, so as between you in 2023 and the folks at Alta Mesa in 2018, who is better positioned to examine the economics of Alta Mesa's ESP program?

MS. GRAGERT: Objection.

THE WITNESS: Do I answer?

MS. GRAGERT: If you can.

A. Well, the one thing that I would say that one difference is, and I think it's a significant difference, when Alta Mesa ran their economics, it was -- I'm sure that it was forward-looking. And

I further certify that pursuant to FRCP Rule 30(e) that the signature by the deponent:

___ was requested by the deponent or a party before the completion of the deposition and is to be returned within 30 days from date of receipt of the transcript. If returned, the attached Errata contains any changes and the reasons therefor;

_X_ was waived by the deponent or a party before the completion of the deposition.

I further certify that I am neither counsel for, related to, nor employed by any of the parties or attorneys in the action in which this proceeding was taken, and further that I am not financially or otherwise interested in the outcome of the action.

Certified to by me this 5th day of November, 2023.

Karen L. Shelton

____

Karen L. Shelton, CSR, RDR, CRR
TX CSR 7050 Exp: 10/31/25
Veritext Legal Solutions
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300 Throckmorton Street
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EXHIBIT C

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

IN RE: ALTA MESA	§	
RESOURCES, INC.	§	CASE NO. 4:19-cv-00957
SECURITIES LITIGATION	§	

ORAL AND VIDEOTAPED DEPOSITION OF MILES PALKE 30(b)(6)
JUNE 13, 2023

ORAL AND VIDEOTAPED DEPOSITION OF MILES PALKE 30(B)(6), produced as a witness at the instance of the Plaintiffs and duly sworn, was taken in the above styled and numbered cause on Tuesday, June 13, 2023, from 9:39 a.m. to 4:06 p.m., before Janalyn Elkins, CSR, in and for the State of Texas, reported by computerized stenotype machine, viz Zoom, pursuant to the Federal Rules of Civil Procedure and any provisions stated on the record herein.

A P P E A R A N C E S

ON BEHALF OF Class Plaintiffs

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BY: BRENDAN BRODEUR
CALLIE CRISPIN
MARIANA ROJAS
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ON BEHALF OF PLAINTIFFS in the Alyeska and Orbis actions

ROLNICK KRAMER SADIGHI LLP
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ON BEHALF OF PLAINTIFFS

LABATON SUCHAROW
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ON BEHALF OF DEFENDANTS - Alta Mesa Resources, Inc., Harlan H. Chappelle, James T. Hackett, Thomas J. Walker, William D. Gutermuth, Jeffrey H. Tepper, Dianna J. Walters, Riverstone Investment Group LLC, Stephen Coats, Michael E. Ellis, Pierre F. Lapeyre, David M. Leuschen, Donald Sinclair, Ronald Smith

LATHAM & WATKINS LLP
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client. The directors can set a tighter tolerance that they want to adhere to, for instance.

Q. And within a reserves audit, does that audit tolerance mean that results within that range of tolerance are deemed acceptable?

A. It -- no, I don't think that's quite right.

Q. So in a reserves audit, what role does the audit tolerance play?

A. So the audit tolerance is applied -- in the case of approved preserves audit, the audit tolerance is applied to the sum total of all proved reserves and whether the estimate of the client and the estimate of the consultant would be within 10 percent on this total basis. However, the letters and the guidelines all state that within that total, individual cases may vary by more than that tolerance.

Q. So the perspective for that audit tolerance is holistic; it's the whole sum of the parts?

A. It's the sum of all the estimate -- all of the assets audited by the consultant or the third party.

Q. Thank you.

Do you see in that same -- sorry, in the next paragraph following the one that referenced Society of Petroleum Engineers, so it's the final sentence that starts on the page ending in Bates 006, it starts with,

"Based on our review."

Do you see that?

A. Yes, I do.

Q. Okay. And it is -- it says, (Reading:) Based on our review including the data, technical processes, and interpretations presented by Alta Mesa, it is our opinion that the overall procedures and methodologies utilized by Alta Mesa in preparing their estimates of the proved reserves as of December 31, 2015 comply with the current SEC regulations.

Did I read that correctly?

A. You did.

Q. And how did Ryder Scott reach the conclusion that Alta Mesa's overall procedures and methodologies used to prepare their estimates of proved reserves as of December 31, 2015 complied with then current SEC regulations?

MR. BRODEUR: Objection.

THE WITNESS: So in order to come to that conclusion, Ryder Scott would have reviewed for the assets that we're auditing how Alta Mesa arrived at their reserves estimates or their proved reserves estimates. And, you know, if they were done with a volumetric approach, we would have asked to see the maps and see the volume calculations. If they were done by

performance methodologies like decline curve analysis, we would have received those from them in an Aries database and we would have looked at how they were drawing their declines.

Q. (BY MR. PETERS) And to the extent applicable, Ryder Scott did, in fact, take those steps and reviewed those materials in connection with preparing this audit -- reserves audit report?

A. Yes, sir.

Q. And, again, Ryder Scott concluded that at the time AMH was in compliance with then current SEC regulations?

MR. BRODEUR: Objection.

THE WITNESS: Yes.

Q. (BY MR. PETERS) And if -- continuing the sentence I just read, it says that the -- it says, (Reading:) That the overall proved reserves for the reviewed properties as estimated by Alta Mesa are in the aggregate reasonable within the established audit tolerance guidelines of 10 percent as set forth in the SPE auditing standards.

Do you see that?

A. I do.

Q. And SPE auditing standards is the Society of Petroleum Engineer standards that we were just

discussing?

A. Yes, sir.

Q. So this reflects -- does this reflect that for the year end for -- reserves audits for the year ending December 31, 2015 that Ryder Scott concluded that the overall proved reserves were within the 10 percent audit tolerance?

MR. BRODEUR: Objection.

THE WITNESS: Yes, sir, that is what that sentence is intended to mean.

Q. (BY MR. PETERS) And that was an accurate statement at the time?

MR. BRODEUR: Objection.

THE WITNESS: What?

Q. (BY MR. PETERS) Reflecting Ryder Scott's conclusion?

A. I'm sure that was our opinion at the time.

Q. If you could stay within the same document, please, and turn to the page that ends in Bates stamp 013.

A. Okay. I'm there.

Q. Do you see a paragraph that starts with, "Certain technical personnel of Alta Mesa"?

A. Yes, sir.

Q. Okay. And the final sentence in that paragraph

says, (Reading:) We consulted with these technical personnel and had access to their work papers and supporting data in the course of our audit.

Do you see that sentence?

A. I do.

Q. And is that an accurate statement?

A. It is, yes.

Q. And do you recall which Alta Mesa technical personnel Ryder Scott consulted with in connection with this reserves audit?

A. So this particular audit was before my direct involvement. But I would say that it would be whatever Mr. Turner's team was that -- it would be Tim Turner and then -- and then whoever was reporting to him and possibly people that worked for the various assets that didn't directly report to him, but were responsible for estimating the reserves for those assets.

Q. And do you recall ever having difficulty connecting with necessary personnel at AMH when Ryder Scott wanted to contact them about a reserves audit?

A. I don't remember difficulties on that front.

Q. And this also -- this sentence also reflects that -- that Ryder Scott had access to those technical personnel's work papers and supporting data.

Do you see that?

A. I do.

Q. And I know this is before your time, but do you know what work papers and supporting data Ryder Scott had access to for this reserves audit?

A. So for this one, you know, we would have had first and foremost their Aries database which contain their projections for their assets. We probably had a number of PowerPoint presentations from them that explained how they were estimating volumes for their particular assets. It would be probably a set of their maps for those assets that were volumetrically calculated.

Q. Anything else that you recall?

A. Not that I recall.

Q. And do you recall, did Ryder Scott raise any concerns about the completeness of the data it received from Alta Mesa?

MR. BRODEUR: Objection.

THE WITNESS: I don't believe so, no.

Q. (BY MR. PETERS) And if Ryder Scott had concerns about the accuracy of data that it received from Alta Mesa, would it have raised those concerns?

A. Yes, if -- well, I mean, can you clarify what you mean by concerns about the accuracy?

Q. Well, if Ryder Scott received information data

from Alta Mesa and believed it was inaccurate in some way, material way, would Ryder Scott have raised that concern with Alta Mesa?
A. If we had reason to believe that the data was somehow incorrect or incomplete, for instance, we would have -- we would have asked that, yes.
Q. And you don't recall any instances where Ryder Scott had to raise that?
A. I don't, no.
Q. I'm going to introduce another exhibit here. It should be up momentarily. It will be Defense Exhibit 20, I believe.
(Exhibit No. DFT 20 was marked.)
THE WITNESS: Okay. I see it. I'm going to bring that up.
Q. (BY MR. PETERS) Okay. Perfect.
A. Okay. I have it.
Q. Mr. Palke, do you recognize this document?
A. I do, yes.
Q. And what is it?
A. So this is the reserves report for December 31, 2016 and it is for Alta Mesa in its entirety including Oklahoma, but other assets as well.
Q. And this is the reserves report for the year ended December 31, 2016 that Ryder Scott prepared; is

Q. Okay. And the access -- so strike that.

So you -- Ryder Scott had access to the papers and data that Alta Mesa provided to Ryder Scott, correct?

A. Yes, sir.

Q. Did Ryder Scott go -- well, go physically into Alta Mesa offices to look at the existing work papers physically onsite?

A. We visited their offices from time to time. In general, what would happen in a meeting like that would be -- either the same files that we're talking about would be presented on a viewer, you know, overhead or what -- overhead -- not overhead, on a projector. And sometimes there would be a map printed in -- on paper and, you know, put on a table to look at or possibly well logs that were printed on paper and laid out on a tabletop.

And those would be the rare occasions where we took something in paper format. It would be a map that Alta Mesa had printed to show us.

Q. So even when you're in Alta Mesa's office, was it true that the data that Ryder Scott was receiving was that data that Alta Mesa decided to bring and present to Ryder Scott?

A. Yes.

Q. All right. You didn't go -- you didn't go into people's desk, you didn't say give us every file you have, you didn't look through people's emails?

A. No. We would request support for a particular number that Alta Mesa presented to us for a particular asset. And depending on what method they had used to do the estimate, they would provide us documentation that supported that estimate.

Q. Okay. Did Alta Mesa ever show you an oil in place map suggesting that Alta Mesa's stack acreage had 33 to 35,000 MBO per section in the Mississippian aged rock in its Oklahoma stack acreage?

A. I don't recall being shown such a document.

Q. Okay. Do you remember Alta Mesa ever sharing an oil in place map with Ryder Scott?

A. Well, in my involvement, no, I don't remember that.

Q. Stepping outside of the context where you're a Ryder Scott personnel and were physically at Alta Mesa's offices, is it true that Ryder Scott received Alta Mesa's Aries database?

A. Yes.

Q. Okay. And other than the Aries database, did Alta Mesa -- excuse me, did Ryder Scott have any sort of direct access into Alta Mesa's contemporaneous

systems, computer systems?

A. No. We were never set up with our own kind of ominous ability to access their files.

Q. So if some data were not put into the Aries database, Ryder Scott simply would not receive that?

A. Well, we also received other file source than just the Aries database. But, I mean, it's safe to say that if we didn't get a file, we didn't see it.

Q. Okay. You didn't conduct an independent search of Alta Mesa's books, records, and computer files?

A. No, that wasn't our engagement.

Q. Are you familiar with a computer platform called Inner Site?

A. I'm not personally familiar with that, no.

Q. Okay. Are you aware that Alta Mesa maintained an Inner Site database?

A. I was not, no.

Q. Did Ryder Scott audit the -- Alta Mesa's Inner Site database in any respect?

A. I don't believe so, no.

Q. Now, Mr. Peters asked you some questions about how Ryder Scott developed a type curve. Do you recall giving testimony on that topic?

A. Yes, sir.

Q. Why -- why would Ryder Scott develop a type

further that I am not financially or otherwise interested in the outcome of the action.

Certified to by me this 15th day of June 2023.

Janalyn Elkins

JANALYN ELKINS
Texas CSR 3631
Expiration Date 1/31/2025
Veritext Legal Solutions
300 Throckmorton Street, Suite 1600
Fort Worth, Texas 76102
Firm Registration No. 571
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UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

IN RE ALTA MESA RESOURCES, INC. SECURITIES LITIGATION	Case No. 4:19-cv-00957 Judge George C. Hanks, Jr.

Notice of Errata – Deposition of Miles Palke (Ryder Scott 30(b)(6)) (June 13, 2023)

I, the undersigned, do hereby declare that I have read the deposition transcript of Miles Palke dated June 13, 2023 and that to the best of my knowledge, said testimony is true and accurate, with the exception of the following changes listed below:

Page	Line(s)	Change		Reason
		From	To	
8	18	"Engineer named Amara Okafor"	"An engineer named Amara Okafor"	Correction
12	18	"economical"	"economic"	Correction
27	14	"if"	"it's"	Correction
34	18-19	"and that it did appear that reanalyzing all the wells and redoing"	"and it did not appear that reanalyzing all the wells and redoing"	Correction
35	19	"Amir"	"Amara"	Correction
36	10-11	"in fill"	"infill"	Correction
45	8	"That is correct, yes"	"That is correct as to all proved undeveloped reserves"	Clarification

Page	**Line(s)**	**Change**		**Reason**
		From	**To**	
51	17	"de-separate"	"separate"	Correction
52	20	"certain basins"	"in certain basins"	Correction
70	10	"there may be odd well"	"there may be an odd well"	Correction
72	20	"for"	"from"	Correction
113	1	"575"	"875"	Correction
120	1	"surround"	"around"	Correction
133	12	"Yes, it is."	"No, it is not."	Correction
148	10	"rowbyte"	"probit"	Correction
149	5	"all the months that"	"all the wells that"	Correction
150	1-2	"depends on what the audit from year to year"	"depends on the audit from year to year"	Correction
156	4	"it's by rig producing"	"it's by proved producing"	Correction
166	3	"ominous"	"autonomous"	Correction
168	18	"worked"	"work"	Correction

I declare under penalty of perjury that the foregoing is true and correct.

Date: July 20, 2023 Signed: ______________________

State of Texas §
§
County of Harris §

This Instrument was subscribed, sworn to and acknowledged before me by Miles R. Palke, on this 20th day of July 2023.

PAMELA L. LESLIE
NOTARY ID #552000-0
My Commission Expires
July 27, 2023

____
Notary Public in and for the State of Texas

EXHIBIT D

ARTIFICIAL LIFT QUOTE

BAKER HUGHES a GE company

Customer	Customer Number	Stat/Segment	Requested Delivery Date	Date
ALTA MESA	**40009006**	CL-1	**10/28/2018**	**10/24/2018**

Sales Order #	Quote Name	Account Manager Info	Quote Expiration	Status
	Mallory 1805 5-30MH Quote #: **10-24-18 LB 01**	**Ed Lorenzen - CL1** **405-837-9063**	**1/22/2019**	

Well Name	Well Number	Field	County	State/Province	AFE	PO
Mallory 1805 5-...		-	**KINGFISHER**	**OK**		

Quote Summary **Standard** ☐ Options

Qty	Material Number	Description	Condition Type	Unit Price	Discount %	Ext Price
Discharge						
1	C63029	400 DSCHG B/O PMP 400 2.87X8 EUE1040	Sale	$45.00		$45.00
Pump						
1	C327798	400 FLEX31 PMSSD 96 H6	Sale	$8,463.95		$8,463.95
1	C327798	400 FLEX31 PMSSD 96 H6	Sale	$8,463.95		$8,463.95
1	C327798	400 FLEX31 PMSSD 96 H6	Sale	$8,463.95		$8,463.95
1	C322919	400 GINPSHL PMSXD 24 H6	Sale	$3,879.55		$3,879.55
Gas Separator / Intake						
1	C329096	400 GSTHVVX LV HEAD GASSEP H6	Sale	$2,775.13		$2,775.13
Seal						
1	C313017048	400 FSB3DB H6	Sale	$3,501.60		$3,501.60
Motor						
1	105106631	450 SP 220 2395 59	Sale	$14,486.00		$14,486.00
Sensor						
1	C1030YCUS	Centinel	Sale	$467.00		$467.00
Coating						
119.2	10182350	Coating	Sale	$30.00		$3,576.00
MLE						
1	C78450M-110	CENTRILINK 12 110 PLHT PK SLV 400F	Sale	$2,069.23		$2,069.23

Cable						
6572	C76141	CELF 4 4SOLBC 5KV DD13 LD B GAL F	Sale	$5.15		$33,845.80
Variable Speed Drive						
1	C907986	ESPD 2250 4ADV 12P2SW CSW	Sale	$27,124.58		$27,124.58
Transformers						
1	C901608	XFMR 260KVA 480/1260-4988 3PH PAD OIL	Sale	$15,042.00		$15,042.00
Miscellaneous Equipment						
1.00	C57304	JBOX ASM 5KV 250A W/LXN SHLD CS 3PH N3R	Sale	$637.35		$637.35
1.00	C903288	INTFC ASM GCS/CE CENTINEL RETROFIT	Sale	$747.00		$747.00
1.00	C903521	SURF INDCTR PKG SIP CHOKE ASM CTL	Sale	$1,104.00		$1,104.00
1.00	C335216	SUREFIELD GLOBAL SN 14614544 IMEI 353938-03-0242758 ICC-ID 898709915412823179 SG 2128	Sale	$5,730.00		$5,730.00
1.00	C909510	KIT MODEM MOUNTING	Sale	$243.00		$243.00
5.00	C62708-5	LUBE OIL CL-5E 10CS 5GL PAIL	Sale	$57.58		$287.90
1.00	C323453	BRKT LWR 5.50 OD MTR 2 3/8 8RD EUE 9.25"	Sale	$126.25		$126.25
1.00	CZ3710	NIP SWG 2.38 E - 3.50 E	Sale	$270.03		$270.03
1.00	C63900	CLR 3.500-8RD EU J55	Sale	$96.82		$96.82
1.00	C326018	ANODE AL 2-3/8"ODX36"	Sale	$190.37		$190.37
2.00	C56728	CLR 2.875-8RD EU J55	Sale	$26.58		$53.16
2.00	C63936	CLR 2.375-8RD EU J55	Sale	$41.25		$82.50
1.00	C31372	NIP SWG 2.875 8RDX2 3/8 8RD XH	Sale	$137.08		$137.08
1.00	C338364	SANDTRAP DWNHL DESANDER 1/2IN F2400-4000	Sale	$5,565.87		$5,565.87
1.00	C31373	NIP SWG 2 7/8 EUE X 3 1/2 EUE	Sale	$175.48		$175.48
210.00	C337886	PROTR CBL XCPLG 2.875IN OD LOW CS Y ZINC	Sale	$65.00		$13,650.00
420.00	10210685	C334152 SLINGCO TBG CLP PIN	Sale	$0.00		$0.00
1.00	C911145	VLV 3/8IN TYLOK X 3/8IN TUBE BALL 316SS	Sale	$75.00		$75.00
1.00	BCAP5000128	CHEM LINE 150PSI CHECK FOR 3/8IN	Sale	$685.00		$685.00
6,585.00	C338445	Cap Tube 3/8"	Sale	$1.70		$11,194.50

Additional Line Items						
1	10538484	Material Surcharge	Sale	$9,470.64		$9,470.64

Freight	Tax Exempt	Preferred Carrier	Condition Type	Unit Price
Pre-Pay & Add	No	Circle V	Freight	

Sales Sub Total (excluding discount):	$182,725.69

Sub Totals (including discount %)

Sales Sub Total:	$182,725.69
Service Sub Total:	$0.00
Trade-in Sub Total:	$0.00
Lease\Rental Sub Total:	$0.00
Freight Total:	
Discount Sub Total:	$0.00
Total excluding taxes, duties, and delivery:	$182,725.69
Total including delivery, excluding taxes and duties:	$182,725.69

Comments: **Customer**
Signature: ______________________________

Copper adder included in cable price.

Note: This quote is subject to Baker Hughes, a GE company Terms and Conditions as below.

NOTE: THIS AGREEMENT CONTAINS PROVISIONS THAT INDEMNIFY AND/OR RELEASE THE INDEMNIFIED AND/OR RELEASED PARTY FROM THE CONSEQUENCES OF ITS OWN NEGLIGENCE AND OTHER LEGAL FAULT.

TERMS AND CONDITIONS

NOTE. THIS AGREEMENT CONTAINS PROVISIONS THAT INDEMNIFY AND/OR RELEASE THE INDEMNIFIED AND/OR RELEASED PARTY FROM THE CONSEQUENCES OF ITS OWN NEGLIGENCE AND OTHER LEGAL FAULT
Orders for rental equipment ("Equipment"), services ("Services"), and the supply or sale of products, chemicals, or equipment ("Products") to be provided by a direct or indirect subsidiary of Baker Hughes, a GE company, LLC (in each case such subsidiary providing the Equipment, Services, or Products covered by the order is referred to herein as "BHGE") to its customers (each a "Customer") are subject to acceptance by BHGE, and any orders so accepted will be governed by the terms and conditions stated herein and any additional terms proposed or agreed to in writing by an authorized representative of BHGE (these terms and conditions and any such agreed additional terms are collectively referred to herein as the "Agreement"). All obligations of BHGE are several and not joint and in no event shall Baker Hughes, a GE company, LLC or any of its direct or indirect subsidiaries that are not providing Equipment, Services, or Products under the order have any liability or obligation with respect to acts or omissions of BHGE.

1. PAYMENT TERMS
Unless alternate payment terms are specified or approved by the BHGE Credit Department, all charges billed by BHGE must be paid within thirty (30) days of the date of invoice. For invoices unpaid after thirty (30) days, at BHGE's option, discounts from list price may be revoked, interest may be charged at the rate often percent (10%) per annum (unless such rate contravenes local law in which case the interest will accrue at the maximum rate allowed by law) and Customer shall pay BHGE all costs of collection, including reasonable attorneys' fees and court costs, in addition to other amounts due. Operating, production or well conditions that prevent satisfactory operation of Equipment, Services or Products do not relieve Customer of its payment responsibility.

2. CANCELLATION AND RETURNS
Products. Except as provided herein, orders for Products that have not yet been delivered will be subject to a restocking charge of at least twenty-five percent (25%), plus any packing and transportation costs incurred before delivery Delivered Products may be returned for credit only with prior written authorization from BHGE Such Products must be unused, in reusable condition, and with original unopened containers. Credit will be issued for the quantity returned at the original purchase price, less a restocking charge of at least twenty-five percent (25%) and any actual packing and transportation costs incurred by BHGE. No credit will be given for shipping charges incurred by Customer. Products specially built or manufactured to Customer specifications, or orders for substantial quantities manufactured specially for Customer, may not be cancelled or returned.
Equipment/Services: In the event Customer cancels an order for Services, Customer shall be liable for all costs incurred by BHGE in the mobilization/demobilization related thereto, and any other reasonable costs incurred by BHGE incident to such cancellation. In the event Customer cancels an order for Equipment, Customer shall be liable for any transportation costs incurred by BHGE in the mobilization/demobilization of the Equipment. In addition, a restocking charge of at least twenty-five percent (25%) of the original Equipment order may be applied at BHGE's sole discretion.

3. THIRD-PARTY CHARGES, TAXES
Customer shall pay all third-party charges, in compliance with BHGE's current price list, and any sales, use, rental or other taxes that may be applicable to transactions hereunder. Customer shall pay all applicable customs, excise, import and other duties unless otherwise agreed to in writing by an authorized representative of BHGE. Customer shall provide necessary import licenses and extensions thereof. If Customer obtains a refund of sales tax applicable to the transactions hereunder by a taxing authority, and BHGE subsequently receives an assessment for use tax by such taxing authority, then Customer shall promptly reimburse BHGE the use tax.

4. RISK OF LOSS AND TITLE, CONSIGNMENT, STORAGE
Unless otherwise agreed to in writing between BHGE and Customer: (i) for Product sales within the United States of America, title and risk of loss shall pass to Customer as soon as the Products depart BHGE's point of origin; and (ii) for Product sales outside the United States of America, INCOTERM 2010 "CPT" shall apply with the following exception: TITLE AND RISK OF LOSS REMAIN WITH BHGE UNTIL THE PRODUCTS REACH THE PORT OF ENTRY For Products provided on consignment, the risk of loss shall pass to Customer as soon as the Products depart BHGE's point of origin; however, the title shall remain with BHGE until the Product is used by Customer.
In the event BHGE agrees to store Products after title passes to Customer, the risk of loss shall remain with Customer If any such Products remain on BHGE's premises for more than two (2) years from the date initially placed in storage, title shall revert back to BHGE, and BHGE may resell or scrap any such Products with no liability to Customer for any proceeds generated therefrom.

5. LIABILITIES, RELEASES AND INDEMNIFICATION:

A. In this Agreement (i) "BHGE Indemnitees" means BHGE, its parent, subsidiary and affiliated or related companies; its subcontractors at any tier; and the officers, directors, employees, consultants, and agents of all of the foregoing; (ii) "Claims" means all claims, demands, causes of action, liabilities, damages, judgments, fines, penalties, awards, losses, costs, expenses (including, without limitation, attorneys' fees and costs of litigation) of any kind or character arising out of, or related to, the performance of or subject matter of this Agreement; (iii) "Consequential Damages" means any indirect, special, punitive, exemplary or consequential damages or losses (whether foreseeable or not at the date of this Agreement) under applicable law and damages for lost production, lost revenue, lost product, lost profit, lost business, lost business opportunities, or charges for rig time, regardless of whether the same would be considered direct, indirect, special, punitive, exemplary or consequential damages or losses under applicable law; (iv) "Customer Indemnitees" means Customer, its parent, subsidiary and affiliated or related companies; its co-lessees, co-owners, partners, joint operators and joint venturers; its client or customer if it is not the end user of the Equipment, Services, or Products; its other contractors at any tier; and the officers, directors, employees, consultants, and agents of all of the foregoing; (v) "Cuttings and Waste" means any drill cuttings and associated muds, waste or materials from the well arising from or processed pursuant to this Agreement; and (vi) "Tools" means Equipment and any of BHGE Indemnitees' instruments, equipment, or tools.

B BHGE SHALL RELEASE, INDEMNIFY, DEFEND AND HOLD CUSTOMER INDEMNITEES HARMLESS FROM AND AGAINST ANY AND ALL CLAIMS ARISING OUT OF OR RELATED TO (I) PERSONAL OR BODILY INJURY, ILLNESS, SICKNESS, DISEASE OR DEATH OF ANY MEMBER OF BHGE INDEMNITEES, AND (II) LOSS, DAMAGE OR DESTRUCTION OF REAL OR PERSONAL PROPERTY, WHETHER OWNED, LEASED, OR CHARTERED, OF ANY MEMBER OF BHGE INDEMNITEES

C. CUSTOMER SHALL RELEASE, INDEMNIFY, DEFEND AND HOLD BHGE INDEMNITEES HARMLESS FROM AND AGAINST ANY AND ALL CLAIMS ARISING OUT OF OR RELATED TO (I) PERSONAL OR BODILY INJURY, ILLNESS, SICKNESS, DISEASE OR DEATH OF ANY MEMBER OF CUSTOMER INDEMNITEES, AND (II) LOSS, DAMAGE OR DESTRUCTION OF REAL OR PERSONAL PROPERTY, WHETHER OWNED, LEASED, OR CHARTERED, OF ANY MEMBER OF CUSTOMER INDEMNITEES.

D. SHOULD TOOLS BECOME LOST OR DAMAGED IN THE WELL OR HOLE WHEN PERFORMING OR ATTEMPTING TO PERFORM THE SERVICES HEREUNDER, IT IS UNDERSTOOD THAT CUSTOMER SHALL MAKE EVERY EFFORT TO RECOVER THE LOST OR DAMAGED TOOLS AT ITS SOLE COST. CUSTOMER SHALL ASSUME THE ENTIRE RESPONSIBILITY FOR FISHING OPERATIONS IN THE RECOVERY OR ATTEMPTED RECOVERY OF ANY SUCH LOST OR DAMAGED TOOLS. NONE OF BHGE'S EMPLOYEES ARE AUTHORIZED TO DO ANYTHING WHATSOEVER, NOR SHALL ANY OF BHGE'S EMPLOYEES BE REQUIRED BY CUSTOMER TO DO ANYTHING, OTHER THAN CONSULT IN AN ADVISORY CAPACITY WITH CUSTOMER IN CONNECTION WITH SUCH FISHING OPERATIONS.
NOTWITHSTANDING PARAGRAPH B. ABOVE, SHOULD CUSTOMER FAIL TO RECOVER SUCH TOOLS LOST IN THE WELL, OR SHOULD SUCH TOOLS BECOME DAMAGED IN THE WELL, OR DAMAGED DURING RECOVERY, CUSTOMER SHALL REIMBURSE BHGE FOR THE COST OF REPAIRING ANY TOOLS SO DAMAGED, OR THE REPLACEMENT VALUE OF ANY SUCH TOOLS THAT ARE LOST OR NOT REPAIRABLE.
FURTHER, NOTWITHSTANDING PARAGRAPH B ABOVE, ALL RISKS ASSOCIATED WITH LOSS OF OR DAMAGE TO TOOLS WHILE IN THE CUSTODY OR CONTROL OF CUSTOMER OR DURING TRANSPORTATION ARRANGED BY OR CONTROLLED BY CUSTOMER, SHALL BE BORNE BY CUSTOMER.

E. NOTWITHSTANDING ANYTHING CONTAINED IN THIS AGREEMENT TO THE CONTRARY, CUSTOMER SHALL RELEASE, INDEMNIFY, DEFEND AND HOLD BHGE INDEMNITEES HARMLESS FROM AND AGAINST ANY AND ALL CLAIMS ASSERTED BY OR IN FAVOR OF ANY PERSON, PARTY, OR ENTITY (INCLUDING BHGE INDEMNITEES) ARISING OUT OF OR RELATED TO. (I) LOSS OF OR DAMAGE TO ANY WELL OR HOLE (INCLUDING BUT NOT LIMITED

TO THE COSTS OF RE-DRILL AND SIDETRACK, (II) BLOWOUT, FIRE, EXPLOSION, CRATERING OR ANY UNCONTROLLED WELL CONDITION (INCLUDING BUT NOT LIMITED TO THE COSTS TO CONTROL A WILD WELL AND THE REMOVAL OF DEBRIS), (III) DAMAGE TO ANY RESERVOIR, GEOLOGICAL FORMATION OR UNDERGROUND STRATA OR THE LOSS OF OIL, WATER OR GAS THEREFROM, (IV) THE USE OF BHGE INDEMNITEES' RADIOACTIVE TOOLS OR ANY CONTAMINATION RESULTING THEREFROM (INCLUDING BUT NOT LIMITED TO RETRIEVAL OR CONTAINMENT AND CLEAN-UP), (V) POLLUTION OR CONTAMINATION OF ANY KIND INCLUDING BUT NOT LIMITED TO THE COST OF CONTROL, REMOVAL, CLEAN-UP AND REMEDIATION, OR (VI) DAMAGE TO, OR ESCAPE OF ANY SUBSTANCE FROM, ANY PIPELINE, VESSEL, OR STORAGE OR PRODUCTION FACILITY.

F. CUSTOMER ACKNOWLEDGES THAT CUTTINGS AND WASTE REMAIN CUSTOMER'S RESPONSIBILITY. CUSTOMER SHALL RELEASE, INDEMNIFY, DEFEND AND HOLD BHGE INDEMNITEES HARMLESS FROM AND AGAINST ANY AND ALL CLAIMS, ASSERTED BY OR IN FAVOR OF ANY PERSON OR ENTITY ARISING OUT OF OR RELATED TO THE TRANSPORTATION, STORAGE, TREATMENT, DISPOSAL OR HANDLING OF CUTTINGS AND WASTE, INCLUDING, WITHOUT LIMITATION, CONTAMINATION OF, OR ADVERSE EFFECTS ON THE ENVIRONMENT OR ANY FORM OF PROPERTY, OR ANY VIOLATION OR ALLEGED VIOLATION OF STATUTES, ORDINANCES, LAWS, ORDERS, RULES AND REGULATIONS (INCLUDING, WITHOUT LIMITATION, ALL CLAIMS UNDER THE COMPREHENSIVE ENVIRONMENTAL RESPONSE, COMPENSATION, AND LIABILITY ACT ("CERCLA"), 42 U.S.C. §§ 9601 ET SEQ., OR OTHER APPLICABLE STATUTES OR REGULATIONS).

G. CUSTOMER SHALL RELEASE, DEFEND, INDEMNIFY AND HOLD BHGE INDEMNITEES HARMLESS FROM AND AGAINST ANY CLAIMS FOR CONSEQUENTIAL DAMAGES ASSERTED BY OR IN FAVOR OF ANY MEMBER OF CUSTOMER INDEMNITEES. BHGE SHALL RELEASE, DEFEND, INDEMNIFY AND HOLD CUSTOMER INDEMNITEES HARMLESS FROM AND AGAINST ANY CLAIMS FOR CONSEQUENTIAL DAMAGES ASSERTED BY OR IN FAVOR OF ANY MEMBER OF BHGE INDEMNITEES.

H. In the event this agreement is subject to the indemnity or release limitations in Chapter 127 of the Texas Civil Practices and Remedies Code (or any successor statute), and so long as such limitations are in force, each party covenants and agrees to support the mutual indemnity and release obligations contained in Paragraphs B. and C. above by carrying equal amounts of insurance (or qualified self-insurance) in an amount not less than U.S. $5,000,000.00 for the benefit of the other party as indemnitee.
I. THE EXCLUSIONS OF LIABILITY, RELEASES AND INDEMNITIES SET FORTH IN PARAGRAPHS B. THROUGH G. OF THIS ARTICLE 5, AND ARTICLES 6 AND 10, SHALL APPLY TO ANY CLAIM(S) WITHOUT REGARD TO THE CAUSE(S) THEREOF INCLUDING BUT NOT LIMITED TO PRE-EXISTING CONDITIONS, WHETHER SUCH CONDITIONS BE PATENT OR LATENT, THE UNSEAWORTHINESS OF ANY VESSEL OR VESSELS, IMPERFECTION OF MATERIAL, DEFECT OR FAILURE OF PRODUCTS, SERVICES OR EQUIPMENT, BREACH OF REPRESENTATION OR WARRANTY (EXPRESS OR IMPLIED), ULTRAHAZARDOUS ACTIVITY, STRICT LIABILITY, TORT, BREACH OF CONTRACT, BREACH OF DUTY (STATUTORY OR OTHERWISE), BREACH OF ANY SAFETY REQUIREMENT OR REGULATION, OR THE NEGLIGENCE, GROSS NEGLIGENCE, WILLFUL MISCONDUCT, OR OTHER LEGAL FAULT OR RESPONSIBILITY OF ANY PERSON, PARTY, OR ENTITY (INCLUDING THE INDEMNIFIED OR RELEASED PARTY), WHETHER SUCH FORM OF NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, ACTIVE OR PASSIVE.
J. REDRESS UNDER THE INDEMNITY PROVISIONS SET FORTH IN THIS ARTICLE5 SHALL BE THE EXCLUSIVE REMEDIES AVAILABLE TO THE PARTIES HERETO FOR THE CLAIMS COVERED BY SUCH PROVISIONS.

6. DIRECTIONAL DRILLING
Customer shall furnish BHGE with a well location plan (certified by Customer as correct) setting out the surface location of the well, the lease, license, or property boundary lines, and the bottom hole location of Customer's directionally drilled well. If, in the course of drilling the well, it becomes evident to BHGE that the certified plan is in error, BHGE shall notify Customer of the error, and Customer shall be responsible to regulate all directional drilling factors so that Customer's well bottom hole location will be situated on Customer's property, license, or leasehold at total depth of the well being drilled. CUSTOMER SHALL RELEASE, DEFEND, INDEMNIFY AND HOLD BHGE INDEMNITEES HARMLESS FROM AND AGAINST ANY CLAIMS ARISING OUT OF, OR RELATED TO, SUBSURFACE TRESPASS ARISING OUT OF DIRECTIONAL DRILLING OPERATIONS OR OTHER OPERATIONS PERFORMED BY BHGE INDEMNITEES OR CUSTOMER INDEMNITEES.

7. CUSTOMER WARRANTY/BINDING AUTHORITY
If Customer is not the sole owner of the mineral interests, the well or the field, Customer's request for Services, Equipment or Products shall constitute Customer's warranty that Customer is the duly constituted agent of each and every owner and has full authority to represent the interests of the same with respect to all decisions taken throughout the provision of any Services, Equipment or Products hereunder. CUSTOMER SHALL RELEASE, DEFEND, INDEMNIFY AND HOLD BHGE INDEMNITEES HARMLESS FROM AND AGAINST ALL CLAIMS RESULTING FROM THE ALLEGATION BY ANY PERSON OR ENTITY THAT CUSTOMER HAS MISREPRESENTED OR LACKED SUFFICIENT AUTHORITY TO REPRESENT SUCH PERSON OR ENTITY AS WARRANTED BY CUSTOMER IN THIS ARTICLE. Furthermore, Customer warrants that the person ordering work from Contractor and/or signing a request for work is fully authorized to do so and Customer waives any claim that such person did not have authority to bind Customer to the Agreement.

8. ACCESS TO WELL AND WELL SITE STORAGE
With respect to onshore and offshore operations, Customer shall provide at its expense adequate means of transportation required for Tools, Products and BHGE personnel to gain access to or return from a well site, and shall obtain at Customer's expense all permits, licenses or other authorization required for BHGE to enter upon work areas for the purposes contemplated. When necessary to repair roads or bridges, or to provide transportation to move Tools, Products or BHGE personnel, such shall be arranged and paid for by Customer.

Customer shall provide proper storage space at the well site, meeting all applicable safety and security requirements and consistent with good industry practices, for the Tools and Products, including, without limitation, all explosive and radioactive materials.

9. RADIOACTIVE SOURCES
Radioactive sources which may be used in BHGE's' Services are potentially dangerous. Customer agrees to comply with all applicable governmental regulations governing the use and handling of radioactive sources. In the event a radioactive source becomes stuck in a well, Customer, at Customer's sole risk and expense will make a reasonable attempt to recover such radioactive source in accordance with 10 C.F.R. § 39.15(a)(1)-(4) or other applicable regulations and use special precautions to prevent damaging the source during recovery operations. If the source cannot be recovered, Customer, at Customer's sole risk and expense, will isolate the radioactive material by cementing it in place or by other means consistent with 10 C.F.R. § 39.15 or other applicable statutes or regulations.

10. WARRANTY

A. Services: BHGE warrants that the Services shall conform to the material aspects of the specifications agreed to in writing by BHGE and Customer. In the event that the Services fail to conform to such specifications, BHGE shall re-perform that part of the non-conforming Services, provided BHGE is notified thereof in writing by Customer prior to BHGE's departure from the work site.

B. Equipment: BHGE warrants that the Equipment will be of the types specified by and agreed to in writing by BHGE and Customer, and will be in good operating condition.

C. Products: (Excluding drill bits, electric submersible pumps and associated cable and surface equipment, specialty chemical Products and specialty Products): BHGE warrants that the Products shall conform to BHGE's published specifications or the specifications agreed to in writing by BHGE and Customer. If any of the Products fail to conform to such specifications upon inspection by BHGE, BHGE, at its option, shall repair or replace the non-conforming Products with the type originally furnished or issue credit to the Customer, provided BHGE is notified thereof in writing within thirty (30) days after delivery of the particular Products.

D. Drill Bits: BHGE warrants that the drill bits to be provided by BHGE pursuant to this Agreement shall conform to BHGE's published specifications. If any of the drill bits fail to conform to such specifications upon inspection by BHGE, BHGE, at its option, shall repair or replace the non-conforming drill bits with the type originally furnished or issue credit to the Customer, provided BHGE is notified thereof in writing within ninety (90) days from the date of shipment.

E. Electric Submersible Pumps and Associated Cable and Surface Equipment: BHGE warrants that the electrical submersible pumps and associated cable and surface equipment to be provided by BHGE pursuant to this Agreement shall conform to BHGE's published specifications. If any of the electric submersible pumps or associated cable or surface equipment fail to conform with such specifications upon inspection by BHGE, BHGE, at its option, shall repair or replace the non-conforming electric submersible pumps or associated cable or surface equipment with the type originally furnished or issue credit to the Customer, provided BHGE is notified thereof in writing within the earlier of twelve (12) months from the date of installation or eighteen (18) months from the date of shipment. Warranty claims by Customer must be submitted to BHGE within sixty (60) days of the failure date of the electric submersible pumps or associated cable or surface equipment.

F. Specialty Chemical Products: BHGE warrants that the specialty chemical Products to be provided by BHGE pursuant to this Agreement shall, upon departure from BHGE's point of origin, conform to the published physical and chemical specifications established

by BHGE for each such Product. If any of the specialty chemical Products fail to conform to such specifications, BHGE, at its option, shall replace the non-conforming specialty chemical Products with the type originally furnished or issue credit to the Customer, provided BHGE is notified thereof in writing within thirty (30) days after the specialty chemical Products depart BHGE's point of origin.

G. Specialty Products: In the event BHGE is to provide Products to Customer based upon Customer's specific request that BHGE develop, manufacture, test or put to use Products that are intended to satisfy a unique need identified by Customer and are not "standard" Products of BHGE, Customer hereby recognizes and agrees that the specialty Products being provided do not necessarily have or contain the same or similar characteristics as BHGE's "standard" Products, including, but not limited to, a historical performance against which future performance can be measured. In developing, manufacturing, testing and putting to use any specialty Products, BHGE will be relying upon information and specifications provided by Customer relating to the unique needs of Customer. As such, BHGE shall have no responsibility for the design, manufacture or engineering of any such specialty Products, even though BHGE may have participated in the development and manufacture of the specialty Products, or for any Customer-furnished materials, information and specifications. If, upon inspection by BHGE, any of the specialty Products fail to meet the specifications agreed to in writing by Customer and BHGE, then BHGE shall, at its option, repair or replace the non-conforming specialty Products with (i) the type originally furnished to Customer, or (ii) substituted Products having BHGE's "standard" specifications and qualifications

H. Discharge Services: Except to the extent that BHGE has agreed to provide its discharge compliance engineering services ("Discharge Services") to Customer pursuant to this Agreement, BHGE shall have no responsibility for achievement of and compliance with any specific oil retention or similar requirements mandated by any applicable local, state or federal law or regulation. If Discharge Services are rendered by BHGE and agreed oil retention or similar requirements are not met, then BHGE shall, at its option, re-perform the Discharge Services, or provide a credit to Customer to cover any documented additional disposal costs incurred by Customer as a result of the nonconforming Discharge Services, provided that such credit shall be limited to 3% of the amount charged for the nonconforming Discharge Services.

BHGE's warranty obligations hereunder are non-transferrable and shall not apply if the non-conformity was caused by (i) Customer's failure to properly store or maintain the Products or Equipment, (ii) abnormal well conditions, abrasive materials, corrosion due to aggressive fluids or incorrect specifications provided by Customer, (iii) unauthorized alteration or repair of the Products or Equipment, (iv) the Products or Equipment are lost or damaged while on Customer's site due to Customer's or any third party's negligence, vandalism or force majeure (including, but not limited to, lightning), or (v) use or handling of the Products or Equipment by Customer in a manner inconsistent with BHGE's recommendations. Further, BHGE's warranty obligations shall terminate if Customer fails to perform its obligations under this or any other Agreement between the parties.

All non-conforming Products shall be delivered to the service facility designated by BHGE. All transportation charges and removal and reinstallation charges related to the repair or replacement of non-conforming Products shall be borne by Customer. Any parts for which BHGE provides replacement under this warranty shall become the property of BHGE. With regard to materials or equipment furnished by third party vendors and/or suppliers, BHGE's liability therefor shall be limited to the assignment of such third party vendor's or supplier's warranty to Customer, to the extent such warranties are assignable. The warranty period for any repaired or replaced Products shall be only for the remainder of the original warranty period.

Interpretations, research, analysis, recommendations, advice or interpretational data (specifically including, without limitation, any preliminary cuttings reinjection program and any engineering designs, geological studies or analyses, well programs, reservoir models, or drilling production optimization or management programs) ("Interpretations and/or Recommendations") furnished by BHGE hereunder are opinions based upon inferences from measurements, empirical relationships and assumptions, and industry practice, which inferences, assumptions and practices are not infallible, and with respect to which professional geologists, engineers, drilling consultants, and analysts may differ. Accordingly, BHGE does not warrant the accuracy, correctness, or completeness of any such Interpretations and/or Recommendations, or that Customer's reliance or any third party's reliance on such Interpretations and/or Recommendations will accomplish any particular results. CUSTOMER ASSUMES FULL RESPONSIBILITY FOR THE USE OF SUCH INTERPRETATIONS AND/OR RECOMMENDATIONS AND FOR ALL DECISIONS BASED THEREON (INCLUDING, WITHOUT LIMITATION, DECISIONS BASED ON ANY OIL AND GAS EVALUATIONS, PRODUCTION FORECASTS AND RESERVE ESTIMATES, FURNISHED BY BHGE TO CUSTOMER HEREUNDER), AND CUSTOMER HEREBY AGREES TO RELEASE, DEFEND, INDEMNIFY AND HOLD BHGE INDEMNITEES HARMLESS FROM ANY CLAIMS ARISING OUT OF THE USE OF SUCH INTERPRETATIONS AND/OR RECOMMENDATIONS.

BHGE will endeavor to transmit data to Customer as accurately and securely as practicable in accordance with current industry practice. Notwithstanding the foregoing, BHGE does not warrant the accuracy of data transmitted by electronic processes and will not be responsible to Customer for accidental or intentional interception of such data by others.

BHGE does not represent or warrant that the Products are or will be compliant with the requirements of REACH (the Registration Evaluation Authorization and Restriction of Chemicals Regulation 1907/2006, as amended) and all implied warranties as to compliance with REACH ("REACH Compliance") are hereby excluded to the fullest extent permitted by law. Without prejudice to the foregoing, BHGE shall use reasonable endeavors to obtain or maintain REACH Compliance in respect of the Products where required by law, unless it is Customer's responsibility to obtain or maintain REACH Compliance or any non-compliance is caused by any act or omission of Customer. In the event BHGE receives written notice from any competent authority, or in its reasonable opinion decides, that any of the Products are not or will not become REACH Compliant, it shall inform Customer in writing within a reasonable time and may suspend any further deliveries of the relevant Products and/or terminate the Order. Customer shall promptly provide such information to BHGE as may be required in order to obtain and maintain REACH Compliance in respect of the Products and shall comply with its obligations under REACH.

THIS ARTICLE 10 SETS FORTH CUSTOMER'S SOLE REMEDIES AND BHGE'S ONLY OBLIGATION WITH REGARD TO DEFECTIVE OR NON-CONFORMING SERVICES, EQUIPMENT OR PRODUCTS. EXCEPT AS IS OTHERWISE EXPRESSLY PROVIDED PURSUANT TO THE PROVISIONS OF THIS ARTICLE 10, BHGE MAKES NO WARRANTY OR GUARANTEE OF ANY KIND, EXPRESS OR IMPLIED, INCLUDING NO IMPLIED WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, REGARDING ANY SERVICES PERFORMED OR EQUIPMENT OR PRODUCTS SUPPLIED BY BHGE HEREUNDER. IN NO EVENT SHALL BHGE BE LIABLE FOR RIG TIME INCURRED BY CUSTOMER INDEMNITEES AS A RESULT OF DEFECTIVE OR NON-CONFORMING SERVICES, EQUIPMENT OR PRODUCTS.

11. LOST EQUIPMENT INDEMNITY BUY-BACK

In some locations, lost equipment indemnity buy-back ("LEIB") is available for some Tools. LEIB must be purchased by Customer prior to the Tools leaving BHGE's point of origin. Regardless of LEIB, Customer shall make every reasonable effort to recover BHGE's Tools lost or damaged in a well or hole in accordance with Paragraph 5D. BHGE reserves the right not to offer LEIB at its sole discretion.

12. INSURANCE

Upon written request, each party shall furnish to the other party certificates of insurance evidencing that adequate insurance to support each party's obligations hereunder has been secured. To the extent of each party's release and indemnity obligations hereunder, each party agrees that all such insurance policies shall (i) be primary to the other party's insurance, (ii) include the other party, its parent, subsidiary and affiliated or related companies, its subcontractors and other contractors, and its and their respective officers, directors, employees, consultants and agents as additional insured, and (iii) be endorsed to waive subrogation against the other party, its parent, subsidiary and affiliated or related companies, its subcontractors and other contractors, and its and their respective officers, directors, employees, consultants and agents.

13. CHANGE OF DESIGN

BHGE expressly reserves the right to change or modify the design and construction of any of its Products without obligation to furnish or install such changes or modifications on Products previously or subsequently sold.

14. PATENTS

BHGE warrants that the use or sale of Equipment or Products hereunder will not infringe valid patents of others by reason of the use or sale of such Equipment or Products per se, and hereby agrees to hold Customer harmless against judgment for damages for infringement of any such patent, provided that Customer shall promptly notify BHGE in writing upon receipt of any claim for infringement, or upon the filing of any such suit for infringement, whichever first occurs, and shall afford BHGE full opportunity, at BHGE's option and expense, to answer such claim or threat of suit, assume the control of the defense of such suit, and settle or compromise same in any way BHGE sees fit. BHGE does not warrant that such Equipment or Products: (i) will not infringe any such patent when not of BHGE's manufacture, or specially made, in whole or in part, to the Customer's design specifications; or (ii) if used or sold in combination with other materials or apparatus or used in the practice of processes, will not, as a result of such combination or use, infringe any such patent, and BHGE shall not be liable and does not hold Customer harmless for damages or losses of any nature whatsoever resulting from actual or alleged patent infringement arising pursuant to (i) and (ii) above. THIS PARAGRAPH STATES THE ENTIRE RESPONSIBILITY OF BHGE CONCERNING PATENT INFRINGEMENT

15. CONFIDENTIALITY

Each party shall maintain all data and information obtained from the other party in strict confidence, subject only to disclosure required by law or legal process. In the event that BHGE owns copyrights to, patents to, or has filed patent applications on, any technology related to the Services, Products or Equipment furnished by BHGE hereunder, and if BHGE makes any improvements on such technology, then such improvements shall not fall within the confidentiality obligations of BHGE included herein, and BHGE shall own all such improvements, including drawings, specifications, calculations and other documents.

The design, construction, application and operation of BHGE's Services, Equipment and Products embody proprietary and confidential information. Customer shall maintain this information in strict confidence and shall not disclose it to others, subject only to disclosure required by law or legal process. To the extent permissible by law, Customer shall not resell the Products or Equipment (or drawings related thereto) to others or reverse engineer or permit others to reverse engineer, for the purpose of manufacturing, similar Products or Equipment.

16. LIENS, ATTACHMENTS AND ENCUMBRANCES
Customer grants to BHGE a lien upon and a security interest in.

(i) any interest that Customer now owns or hereafter acquires in the lands, leasehold interests, pipelines, pipeline right-of-ways, personal property and fixtures arising out of, pertaining to, located on, or used in connection with the development of, the mineral property on which the Services, Products, or Equipment were performed or installed (the "Mineral Property"),

(ii) the oil and gas when extracted from the Mineral Property, including the proceeds thereof, and any producer's lien rights attaching thereto, (iii) the contract rights, inventory and general intangibles pertaining to the Mineral Property, and (iv) any claim against any working interest owner of the Mineral Property arising from nonpayment of joint interest billings, lease operating expenses, or otherwise. This lien and security interest shall be for the purpose of securing performance of Customer's obligations to BHGE under this Agreement. All of BHGE's lien rights, whether arising hereunder or under applicable law, are enforceable at BHGE's discretion, in arbitration or in any court of competent jurisdiction, notwithstanding Article 20. Customer authorizes BHGE to have filed a financing statement and any other instruments BHGE determines to be necessary or appropriate to perfect the lien and security interest created hereby. Upon request, Customer shall execute any document determined by BHGE to be necessary or appropriate to perfect this lien and security interest under all applicable laws and the real property recording statutes of the state in which the Mineral Property is located. If BHGE is unable to obtain proper execution of such documentation within a reasonable period of time after the request is made, then Customer hereby appoints BHGE as Customer's true and lawful agent and attorney-in-fact, to execute all documents on its behalf, and to otherwise take such actions on its behalf, as BHGE deems necessary or appropriate, to perfect the lien and security interest created or contemplated hereby. This appointment is coupled with an interest and may not be revoked for as long as any portion of Customer's obligations hereunder remain outstanding. The lien and security interest created hereby are in addition to, and not in lieu of, any other liens and security interests now existing or hereafter coming into existence, and securing the performance of Customer's obligations hereunder, whether voluntary or involuntary, including any liens arising by statute or common law in favor of mechanics and/or materialmen.
Should Customer. (i) commit a breach of any of the terms and conditions of this Agreement, (ii) be named as a debtor in a bankruptcy proceeding, (iii) become insolvent, (iv) become, or any of its assets become, the subject of a receivership proceeding, or should any creditor or other person or entity attach or levy Customer's property or equipment, BHGE shall immediately have the right, without notice and without liability for trespass or damages, to retake and remove any of its Products or Equipment wherever they may be found. CUSTOMER SHALL RELEASE, DEFEND, INDEMNIFY AND HOLD BHGE INDEMNITEES HARMLESS FROM ANY AND ALL LIENS AND ENCUMBRANCES AGAINST PRODUCTS OR EQUIPMENT FURNISHED HEREUNDER AND SHALL RETURN SAME PROMPTLY TO BHGE FREE OF ANY LIENS OR ENCUMBRANCES.

17. FORCE MAJEURE
If either party is unable by reason of Force Majeure to carry out any of its obligations under this Agreement, other than obligations to pay money, then on such party giving notice and particulars in writing to the other party within a reasonable time after the occurrence of the cause relied upon, such obligations shall be suspended. "Force Majeure" shall include any event that is beyond the reasonable control of the party so affected including, without limitation, acts of God, laws and regulations, government action, war, civil disturbances, hijack, piracy, criminal action by a third party, threats or acts of terrorism, strikes and labor problems, delays of vendors or carriers, lightening, fire, flood, washout, storm, breakage or accident to equipment or machinery, and shortage of raw materials. In the event that any suspension due to Force Majeure exceeds ten (10) consecutive days, either party may terminate this Agreement by written notice to the other party and Customer shall be liable for demobilization and any other reasonable costs incurred by BHGE incidental to such termination.

18. INDEPENDENT CONTRACTOR
It is expressly understood that BHGE is an independent contractor, and that neither BHGE nor its principals, partners, employees or subcontractors are servants, agents or employees of Customer. In all cases where BHGE's employees (defined to include BHGE's and its subcontractors' direct, borrowed, special, or statutory employees) are covered by the Louisiana Workers' Compensation Act, La. R.S. 23:102 et seq., BHGE and Customer agree that all Services, Products and Equipment provided by BHGE and BHGE's employees pursuant to this Agreement are an integral part of and are essential to the ability of Customer to generate Customer's goods, products, and services for the purpose of La. R.S. 23:106 (A) (1). Furthermore, BHGE and Customer agree that Customer is the statutory employer of BHGE's employees for purposes of La. R.S. 23:1061 (A) (3).

19. LAWS, RULES, REGULATIONS, AND EXPORT CONTROL
BHGE and Customer agree to be subject to all laws, rules, regulations and decrees of any governmental or regulatory body having jurisdiction over the Services, Equipment or Products to be provided by BHGE or the work site or that may otherwise be applicable to BHGE's or Customer's performance under this Agreement
Customer acknowledges that Equipment, Services, Products and/or related technical data covered by this Agreement may be subject to U.S. and/or foreign trade controls. Customer agrees that it will not sell, re-export or transfer Equipment, Products and/or related technical data except in full compliance with all governmental requirements including but not limited to economic sanctions and export controls administered by the U.S. Department of Treasury, U.S. Department of Commerce and U.S. Department of State. Customer agrees to comply with all BHGE requests for trade compliance information, statements, and other assurances including, without limitation, requests for End-User and Routed Transaction certifications. Any breach of this provision shall be deemed a material breach of this Agreement and sufficient basis for BHGE to reject any or all orders or to terminate the Agreement.
BHGE reserves the right to refuse to fulfill any order or otherwise perform under this Agreement if BHGE in its sole discretion determines that such action may violate any law or regulation. Customer agrees that such refusal, cancellation, or termination of the Agreement by BHGE will not constitute a breach of BHGE's obligations under this Agreement and Customer hereby waives any and all claims against BHGE related to such refusal, cancellation, or termination.
To the extent that any provision of this Agreement would cause any party to violate or be penalized under the laws of the U.S., that provision shall not apply, shall not be enforceable, and shall not be interpreted as part of this Agreement.

20. GOVERNING LAW AND ARBITRATION
A. Except for Services, Equipment or Products provided, or to be provided, by BHGE in North or South America (the "Americas"): THIS AGREEMENT SHALL BE GOVERNED BY AND INTERPRETED IN ACCORDANCE WITH ENGLISH LAW, EXCLUDING CONFLICTS OF LAW AND CHOICE OF LAW PRINCIPLES. ANY DISPUTE, CONTROVERSY OR CLAIM ("DISPUTE") ARISING OUT OF OR IN CONNECTION WITH THIS AGREEMENT OR THE FURNISHING OF EQUIPMENT, SERVICES OR PRODUCTS HEREUNDER SHALL BE RESOLVED BY FINAL AND BINDING ARBITRATION CONDUCTED IN ACCORDANCE WITH THE UNCITRAL ARBITRATION RULES (THE "RULES"). The Tribunal shall be composed of three arbitrators, with each party appointing one arbitrator, and the two arbitrators so appointed appointing the third arbitrator who shall act as the presiding arbitrator of the Tribunal (the "Tribunal"). The appointing authority under the Rules shall be the London Court of International Arbitration. The language of the arbitration shall be English. The seat of arbitration shall be London, England, and the proceedings shall be conducted and concluded as soon as reasonably practicable, based upon the schedule established by the Tribunal. Any monetary award shall be made in U.S. Dollars, free of any tax or other deduction, and shall include interest from the date of any breach or other violation of the Agreement to the date paid in full at a floating rate of interest equal to the prime rate of interest in effect at Citibank, N.A., New York, U.S.A., from time to time.

B. For Services, Equipment or Products provided, or to be provided, by BHGE in the Americas: THIS AGREEMENT SHALL BE GOVERNED BY AND INTERPRETED IN ACCORDANCE WITH THE SUBSTANTIVE LAWS OF TEXAS, EXCLUDING CONFLICTS OF LAW AND CHOICE OF LAW PRINCIPLES. ANY DISPUTE, CONTROVERSY OR CLAIM ("DISPUTE") ARISING OUT OF OR IN CONNECTION WITH THIS AGREEMENT OR THE FURNISHING OF EQUIPMENT, SERVICES OR PRODUCTS HEREUNDER SHALL BE RESOLVED BY FINAL AND BINDING ARBITRATION CONDUCTED IN ACCORDANCE WITH THE COMMERCIAL RULES OF ARBITRATION OF THE AMERICAN ARBITRATION ASSOCIATION (THE "RULES"). The tribunal shall be composed of one (1) neutral arbitrator if the Dispute involves a maximum exposure of less than $1,000,000. If the parties are unable to agree on a neutral arbitrator, one will be appointed pursuant to the Rules. If the Dispute involves a maximum exposure equal to or in excess of $1,000,000, then the Tribunal shall consist of three (3) arbitrators, with each party appointing one arbitrator, and the two arbitrators so appointed appointing the third arbitrator who shall act as Chair (the "Tribunal"). The seat of arbitration shall be Houston, Texas, and the proceedings shall be conducted and concluded as soon as reasonably practicable, based upon the schedule established by the Tribunal.
C. For any arbitration conducted in accordance with Paragraph A. or B. above, the following shall apply: No award shall be made for Consequential Damages. Judgment upon the award rendered by the Tribunal pursuant hereto may be entered in, and enforced by, any court of competent jurisdiction. All statutes of limitation that would otherwise be applicable shall apply to the arbitration proceeding. Any attorney-client privilege and other protection against disclosure of privileged or confidential information, including, without limitation, any protection afforded the work-product of any attorney, that could otherwise be claimed by any party shall be available to, and may be claimed by, any such party in any arbitration proceeding. The parties shall treat all matters relating to the arbitration as confidential. Subject to each party's right to cooperate fully with the United States authorities, the parties understand and agree that this confidentiality obligation extends to information concerning the fact of any request for arbitration, any ongoing arbitration, as well as all matters discussed, discovered, or divulged, (whether voluntarily or by compulsion) during the course of such arbitration proceeding. It is the desire of the parties that any Dispute is resolved efficiently and fairly and the Tribunal shall act in a manner consistent with these intentions

21. ASSIGNMENT
BHGE shall have the right to assign this Agreement to any of its subsidiaries, affiliated or related companies without the consent of Customer.

22. GENERAL

Failure of Customer or BHGE to enforce any of the terms and conditions of this Agreement shall not prevent a subsequent enforcement of such terms and conditions or be deemed a waiver of any subsequent breach. Should any provision of this Agreement, or a portion thereof, be unenforceable or in conflict with governing country, state, province, or local laws, then the validity of the remaining provisions, and portions thereof, shall not be affected by such unenforceability or conflict, and this Agreement shall be construed as if such provisions, or portion thereof, were not contained herein. This Agreement contains all representations of the parties and supersedes all prior oral or written agreements or representations. Customer acknowledges that it has not relied on any representations other than those contained in this Agreement. This Agreement shall not be varied, supplemented, qualified, or interpreted by any prior course of dealing between the parties or by any usage of trade and may only be amended by an agreement executed by both parties. In the event that any conflict exists between the provisions of this Agreement and any other terms and conditions set forth in Customer's purchase orders, field work orders, work tickets, invoices, statements, or any other type of memoranda or other documents used by Customer in the normal course of business, whether oral or written, the provisions of this Agreement shall govern.

EXHIBIT E

ESP Install Order

DONE
NEXT
NOT DOING

CURRENTLY WORKING

Well Name	WI	WO Ending	Actual Startup	Production HIT	Actual Wedge	Aries Rate Used	Wedge	Current Oil	Current Water	Current Gas	Total Fluid	ESP Total Fluid	Prod Diff. (TF)	Liner Top	PBHP	PI	Clean out	AFE Amt in Aries	Total AFE	Calculated Net AFE Amt Incl $40k
Todd 1706 6-4MH	93.98%	4/23/18	4/25/18	5/23/18			247	30	1,287	8	1317	2634	1317	7368	1624	2.624	50,000	266,947	270,628	291,928
Ash 1705 4B-19MH	100.00%	4/28/18	4/28/18	5/28/18			290	-	581	140	581	1162	581	7148	1154	2.154	50,000	259,947	262,293	302,293
The Trick 1706 1-2MH	96.36%	5/3/18	5/3/18	6/2/18			250	-	1,791	550	1791	3500	1709	7208	2435	3	50,000	266,947	287,940	316,003
Paris 1706 3-28MH	100.00%	5/8/18	5/6/18	6/7/18			307	92	721	362	813	1626	813	7620	1507	2.507	50,000	259,947	294,066	334,066
Shimanek	100.00%	5/18/18	5/19/18	6/17/18			223	223	656	83	879	1758	879		1603	2.603			291,328	331,328
Carey 1805 5-6MH	19.10%	5/23/18	5/24/18	6/25/18			392	-	1,017	-	1017	3000	1983	7126	2320	3.32	50,000	270,628	287,940	62,643
Wishbone	84.09%	5/31/18	5/30/18	6/30/18			322	37	817	1	854	1708	854		1568	2.568			287,940	275,765
Steele	65.37%	6/15/18	6/8/18	6/30/18			462	-	1,100	-	1100	2200	1100		2200	3.2			389,861	281,005
Sawgrass 1705 1-32MH	18.78%	6/10/18	6/12/18	7/25/18			265	-	646	105	800	1600	800	7235	1601	2.601	50,000	257,530	291,328	62,223
Motorhead	13.73%	6/20/18	6/18/18	7/20/18			327	110	930	624	1040	2080	1040		1500	2.5			291,328	45,498
Sadiebug	57.60%	6/22/18	6/26/18	7/22/18			262	110	778	237	888	1776	888		1241	2.241			413,000	260,917
Trick 10-2	97.35%	6/30/18	6/30/18	7/30/18			577	150	1,580	175	1730	3460	1730		2908	3.908			410,000	438,075
Pinehurst	75.75%	6/27/18	7/4/18	7/27/18			328	84	897	108	981	1962	981		1710	2.71			411,000	341,628
Vedajac	52.01%	7/15/18	7/13/18	8/14/18			268	268	362	1,078	630	1260	630		843	1.843			413,000	235,623
Old Crab 1-24	80.87%	7/10/18	7/11/18	8/9/18			462	-	1,100	804	1100	2200	1100		2344	3.344			413,000	366,321
Zeppelin 1606 1-10MH	40.88%	6/10/18	7/11/18	7/10/18			302	30	760	72	790	1580	790		1692	2.692			413,000	185,177
Oak Tree 1-30	97.97%	7/5/18	7/17/18	8/4/18			266	152	844	247	996	1992	996		1170	2.17			413,000	443,792
Niko 5	62.13%	7/25/18	7/11/18	8/24/18			170	60	487	74	547	1094	547		2042	3.042			413,000	281,444
Helen	100.00%	7/10/18	7/26/18	8/9/18			208	63	583	375	646	1292	646		904	1.904			413,000	453,000
Miller	65.28%	7/20/18	7/30/18	8/19/18			345	390	1,929	885	2319	4638	2319		2105	3.105			413,000	295,718
MacKelvey	45.31%		8/2/18	1/30/00			353	353	352	910	705	1410	705		629	1.629			413,000	205,254
Matheson	100.00%	8/1/18	8/4/18	8/31/18			139	133	515		648	1296	648		1367	2.367			413,000	453,000
Bugabago	65.66%	8/1/18	8/7/18	8/31/18			357	-	850	-	850	1700	850		812	1.812			413,000	297,440
Lil Sebastian 1-24	12.89%	8/1/18	8/14/18	8/31/18		615	410	410	591	1,072	1001	2002	1001		1043	2.043			413,000	58,392
Peat 10-26	47.37%	8/1/18	8/14/18	8/31/18			227	227	609	579	836	1672	836		1304	2.304			413,000	214,586
Slugworth 3		8/1/18	8/16/18	8/31/18																
Orbit	56.81%	8/1/18	8/19/18	8/31/18		1,196	797	797	669	1,501	1466	2932	1466		1671	2.671			413,000	257,349
Odie 4-12	85.74%	8/1/18	8/22/18	8/31/18			342	130	994	702	1124	2248	1124		1091	2.091			413,000	388,402
LG Greene 5	83.33%	9/1/18		10/1/18		350	233	233	629		862	1724	862		1326	2.326			413,000	377,485
Mackey 5	96.21%	9/1/18		10/1/18		265	275	127	831		958	1916	958		1254	2.254			413,000	435,831
Crosswhite	99.71%	8/1/18	8/23/18	8/31/18			255	-	607		607	1214	607		1378	2.378			413,000	451,686
Lankard 7-34	57.04%	9/1/18		10/1/18		288	296	140	897		1037	2074	1037		1838	2.838			413,000	258,391
Shutler (second time)		9/1/18		10/1/18			100	100	350		450	900	450			1			413,000	
Beowulf 1805 5-31MH (New Completion)																				
Huntsman 1-23	15.05%	8/1/18		8/31/18			150	-	1,000	15	1000	2000	1000		2044	3.044			413,000	68,177
Hasley (second time) estimated pressure decline	19.66%	9/1/18		10/1/18		228	228	114	700		814	1628	814		950	1.95			413,000	89,060
Wickerman	47.00%	9/1/18		10/1/18		422	281	281	795	937	1076	2152	1076		1035	2.035			413,000	212,910
Waylon (second time)	63.37%	9/1/18		10/1/18		197	273	60	734		794	1588	794		1056	2.056			413,000	287,066
Gregory (second time)	91.74%	9/1/18		10/1/18		73	96	25	262		287	574	287		900	1.9			413,000	415,582
Clark 5-12 (second time)	97.13%	9/21/18		10/21/18		211	162	130	321	390	451	902	451		900	1.9			413,000	439,999
Walrus 1						-														
Redbreast 4-7																				
White King 1						-														
Mad Hatter 2																				
Skippy																				
Scout 1906 1-34	55.71%	9/21/18		10/21/18		191	127	127	253	134	380	760	380		839	1.839			413,000	252,366
Lankard 6 (Second time, est. on Lankard 7 wedge)	57.04%	9/21/18		10/21/18		150	150	-	350	50	350	700	350		1000	2			413,000	258,391
Slugworth 1	86.02%	9/21/18		10/21/18		136	272	-	648	31	648	1296	648		1285	2.285			413,000	389,671

Caterpillar 1506 1-11MH (Frac Hit BHP Estimated)		25.00%		10/15/18	315	210	210	225	575	435	870	435		1800	2.8			413,000	113,250
Elixir		45.00%	8/1/18	8/31/18	335	223	223	238	318	461	922	461		610	1.61			413,000	203,850
Maly 32					125	83	83	247	102	330	660	330		1800	2.8				
Best Thirty (Second Time - Waiting on Survey)		89.89%	10/15/18	11/14/18	101	176	13	437	16	450	900	450		950	1.95			345,000	346,077
White Rabbit 2 (Original Well) (Frac Hit BHP Estimated)						120	120	431	288	551	1102	551		1800	2.8				
Mad Hatter 5 (New Completion)										0	0	0			1				
Casper 3 (New Completion)										0	0	0			1				
Whiskeyfeet 1606 7-2MH		72.76%	10/15/18	11/14/18	261	174	174	557	230	731	1462	731		1353	2.353			370,000	298,316
Spieth (New Completion)										0	0	0			1				
White Rabbit 7 (New Completion)										0	0	0			1				
Bollenbach 4-21 (Original Well) (Frac Hit BHP Estimated)						165	69	489	561	558	1116	558		1800	2.8				
Boecher 4-19 (Original Well) (Frac Hit BHP Estimated)						102	48	309	350	357	714	357		1800	2.8				
Toro Toro (New Completion)										0	0	0			1				
Mallory 1805 5-30MH			11/1/18	11/1/18	551	368	367	1,403	455	1770	3540	1770		1900	2.9			416,000	
Cheshire Cat 1 (Frac Hit BHP Estimated)						98	70	329	310	399	798	399		1800	2.8				
Cheshire Cat 4 (New Completion)										0	0	0			1				
Dalwhinnie 8 (Estimated BHP)						337	337	1,138	408	1475	2950	1475		1500	2.5				
Terminus (New Completion)										0	0	0			1				
Yellowstone (Estimated BHP)							30	460	301	490	980	490		1200	2.2				
Redbreast 3-7 (Original Well) (Frac Hit BHP Estimated)							178	1,358	611	1536	3072	1536		1800	2.8				
Slugworth 4 (Estimated BHP)							330	281	303	611	1222	611		800	1.8				
Walrus 10 (Estimated BHP)							419	398	659	817	1634	817		1000	2				
Bollenbach 2-27 (Original Well)										0									
Fazio 1	Original Well on Pad ("Parent")									0									
Fazio 3	New Completions									0									
Tullamore 1706 9-7MH	Original Well on Pad ("Parent")									0									
Tullamore 1706 5-7MH	New Completions									0									
Aberlour																			
Valor										0									
Hilltop																			
Lil Sebastian 1606 7-24MH																			
Springer																			
										0	0	0			1				
										0	0	0			1				
										0					1				
										0									
Hasley 1605 1-28MH		19.66%		7/20/18		254	112	854	659	966	1932	966	7027	1126	2.126	50,000	262,293	262,293	59,419
Pollard		54.55%		1/30/00		335	335	648	1,392	983	1966	983		1045	2.045			291,328	180,739
LNU 83-2HO - Hinkle				1/30/00		446				0	2000	2000		1187	2.187				
EHU 240H				7/10/18		249	18	596	55	614.37	1228.7	614.37		1197	2.197				
EHU 229H		19.69%	6/15/18	7/15/18		242	135	678	62	813	1626	813		1461	2.461			230,000	53,158
EHU 239H				7/5/18		332	20	398	-	418	836	418		1149	2.149				
EHU 237H				8/4/18		70				0	0	0			1				
EHU 241H			1/0/00			92	-	219	97	219	438	219		1281	2.281				
Todd 1706 7-4MH		99.85%		1/30/00		324	267	763	836	1030	2060	1030	7464	1301	2.301	50,000	255,947	257,530	297,084
Foster 1706 7-24MH		63.30%		6/15/18		239	-	665	48	665	1330	665	7119	944	1.944	50,000	262,293	262,293	191,351
Hoskins 1705 10-9MH		79.55%		6/20/18		173	277	480	889	757	1514	757	6858	865	1.865	50,000	262,293	262,293	240,474
Shutler 1706 1-32MH		16.13%		7/30/18		182	152	498	1,023	650	1300	650	7560	1039	2.039	50,000	257,530	262,293	48,766
Bunker Buster 1606 1-13MH			6/5/18	7/5/18		574	574	442	2,443	1016	2032	1016		942	1.942			291,328	
Peat		5.12%	7/15/18	8/14/18		315	10	764	27	774	1548	774		1982	2.982			413,000	23,203
Themer 1706 2-6MH		78.98%		1/30/00		413	338	370	1,138	708	1416	708	7540	680	1.68	50,000	259,947	262,293	238,751
EHU 236H - Hinkle				1/30/00		334				0	1800	1800		969	1.969				
Plumpjack		98.44%		1/30/00		163	96	521	803	617	1234	617		891	1.891			291,328	326,159
Rowdy		36.69%		1/30/00		347	347	380	881	727	1454	727		964	1.964			291,328	121,564
Martin		91.34%		1/30/00		193	77	567	1,340	644	1288	644		975	1.975			291,328	302,635

EHU 217	98.44%	6/18/18	6/15/18		210	-	500	-	500	1000	500	1201	2.201		399,000	432,143
EHU 218	98.44%	6/18/18	6/15/18		210	-	500	-	500	1000	500	1450	2.45		399,000	432,143
Gregory									0	0	0	956	1.956			
Niko 1			1/30/00		248	248	568	714	816	1632	816	1805	2.805		413,000	
Niko 3									0			1662	2.662		413,000	
Niko 6					227	227	397	642	624	1248	624	1688	2.688		413,000	
EHU 234			1/30/00						0							
LSEOU 43-3HO									0							
LSEOU 97-3HO									0							
LSEOU 89-2H									0							
Exaggerator									0							
Hawk					74	70	273	345	343	686	343	763	1.763		413,000	
Shutler					134	115	477	859	592	1184	592	949	1.949		413,000	
Zeppelin 6-10					222	222	243	873	465	930	465	1055	2.055		413,000	
Fireball					222	216	826	1,656	1042	2084	1042	1132	2.132		413,000	
Oak Tree 1-30					248	132	772	267	904	1808	904	1425	2.425		413,000	
Waylon					275	139	846	648	985	1970	985	1368	2.368		413,000	
Oak Tree 1-30		7/5/18	8/4/18		495	495	553	1,414	1048	2096	1048	1170	2.17		413,000	
Bates	100.00%	8/1/18	8/31/18		65	27	193		220	440	220	620	1.62		413,000	453,000
Beyer	98.23%	8/1/18	8/31/18		131	-	311		311	622	311	1567	2.567		413,000	444,982
Boecher 4-19 ???	90.96%	8/1/18	8/31/18		105	65	340		405	810	405	848	1.848		413,000	412,049
Best Thirty	89.89%	8/1/18	8/31/18		175	-	416		416	832	416	1003	2.003		413,000	407,202
Huntsman 7-23	86.65%	8/1/18	8/31/18		330	330	447	731	777	1554	777	993	1.993		413,000	392,525
Odie 6-12	85.74%	8/1/18	8/31/18		112	112	374		486	972	486	1004	2.004		413,000	388,402
Old Crab 3-24	99.53%	8/1/18	8/31/18		263	263	215	681	478	956	478	851	1.851		413,000	450,871
Speyside 3-27	56.03%	8/1/18	8/31/18		219	99	657	556	756	1512	756	860	1.86		413,000	253,816
Sawgrass 10-32	94.14%	8/1/18	8/31/18		222	200	783	517	983	1966	983	1265	2.265		413,000	426,454
Lankard 9-34	11.41%	8/1/18	8/31/18		200	-	1,019	27	1019	2038	1019	1671	2.671		413,000	51,687
Rigdon	99.48%	8/1/18	8/31/18	467	311	311	786	911	1097	2194	1097	1433	2.433		413,000	450,644
Clark 5-12	97.13%	8/1/18	8/31/18	282	188	188	670	1,517	858	1716	858	916	1.916		413,000	439,999
Musick	99.38%	8/1/18	8/31/18	70	93	23	254	271	277	554	277	749	1.749		413,000	450,191
The Trick 5-2	97.35%	8/1/18	8/31/18	236	169	152	612	894	764	1528	764	1140	2.14		413,000	440,996
The Trick 7-2	97.35%	8/1/18	8/31/18	383	255	255	607	900	862	1724	862	1279	2.279		413,000	440,996
Old Crab 6-24	99.53%	8/1/18	8/31/18	465	310	310	401	845	711	1422	711	905	1.905		413,000	450,871
Old Crab 7-24	99.53%	8/1/18	8/31/18	320	213	213	465	481	678	1356	678	1158	2.158		413,000	450,871
Todd 10-4		8/1/18	TRUE						0	0	0		1		413,000	
Fireball - Updated Prod 8/7/18 - Est. FBHP	19.51%	8/15/18	9/14/18	241	201	141	673	1,315	814	1628	814	1000	2		413,000	88,380
Waylon - Updated Production 8/7/18 - Est. FBHP	63.37%	8/15/18	9/14/18	207	197	108	619	642	727	1454	727	1150	2.15		413,000	287,066
Mackey 1	96.21%	9/1/18	10/1/18	325	247	202	866		1068	2136	1068	1178	2.178		413,000	435,831
Speyside 4-27	56.03%	9/1/18	10/1/18	270	180	180	568		748	1496	748	982	1.982		413,000	253,816
Odie 10	85.74%	9/1/18	10/1/18	219	146	146	359		505	1010	505	856	1.856		345,000	330,099
Farrar 1806 1-32	57.46%	9/1/18	10/1/18	114	81	73	294		367	734	367	888.8	1.8888		345,000	221,221
Zeppelin 5-10	45.89%	9/1/18	10/1/18	172	203	70	580	662	650	1300	650	1328	2.328		413,000	207,882
Niko 1 (Estimated PBHP Drawdown)	12.34%	9/1/18	10/1/18	195	130	130	348	454	478	956	478	1400	2.4		345,000	47,509
Red Queen 1-1 (NEW SURVEY)	14.92%	9/21/18	10/21/18	78	106	25	287	1,100	312	624	312	802	1.802		345,000	57,442
Raisin Cane 1905 1-8	82.42%	9/21/18	10/21/18	110	73	73	124	415	197	394	197	599	1.599		413,000	373,363
Oak Tree 5-30	97.97%	9/21/18	10/21/18	306	239	186	186	834	372	744	372	740	1.74		413,000	443,804
LNU 119-2HO	17.94%	10/15/18	11/14/18	46	57	17	160	16	177	354	177	484	1.484		290,000	59,202
Daydrinker									0							
Straight Edge									0							
Slaughterhouse									0							
Slaughterhouse									0							
Straight Edge									0							
									0							
Boecher (New Completion)									0							
Evelyn 1706 7-18MH									0							

Evelyn 1706 5-18MH	Original Well on Pad ("Parent")						0					
Cleveland	Original Well on Pad ("Parent")						0					
Cleveland	New Completions						0					
							0					
Pollard 1805 3-2 (second time)		9/1/18	10/1/18	120	120	327	447	894	447		1	413,000
Vadder 1805 2-12RMH		9/1/18	10/1/18	150	47	423	470	940	470	629	1.629	413,000
Wendt 1805 1-26		9/1/18	10/1/18	120	120	142	262	524	262		1	413,000
Raisin Cane 1905 1-8		9/1/18	10/1/18	#DIV/0!	-	-	0	0	0		1	413,000
Red Queen 2							0					
Speyside 1							0					
Clark							0					
Niko 1							0					

EXHIBIT F

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SPE-181233-MS

Artificial Lift Selection Strategy to Maximize Unconventional Oil and Gas Assets Value

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This paper was prepared for presentation at the SPE North American Artificial Lift Conference and Exhibition held in The Woodlands, Texas, USA, 25–27 October 2016.

Abstract

The challenges of producing and lifting unconventional oil and gas economically is no doubt the most daunting phase of unconventional oil and gas development. The traditional approach of lift selection is no longer sufficient to effectively manage unconventional wells, with high decline rates between 40 to 80% in the first year. Slug flow, high free gas production, solid (proppant, scale, paraffin), horizontal wellbore geometry, surface pad for multi-well in a cellar, and other unique unconventional wells problems are continuously testing the limit of our existing artificial lift systems. As it might be expected, this is invariably, affecting the economic viability of unconventional oil and gas production.

This paper presents an exceptional Artificial Lift selection process, required to maximize unconventional oil and gas asset value. The presentation includes a case study of Permian Delaware basin unconventional formations. The lift evaluation process which includes, a combination of several output from various models (reservoir, well and economic models) developed to analyze the economic impact of various artificial lift selection on the well-life is also presented.

Three distinct periods are defined for the analysis:

1.) Managed Flow-Back
2.) Managed Production (Managed Drawdown)
3.) End of Life

The overarching impact of lift selection and application, on Lease Operating Expense (LOE), Net Present Value of Cash Flow, Overall Asset Value Rate of Return on Investment and other Economic Indicators, for oil and gas operators is highlighted in this paper.

Artificial Lift Types were evaluated based on several criteria through elimination and selection techniques. Artificial Lift is phased over the life of the well according to current and expected production rate requirement and lift method capability. Other major consideration includes flexible rate delivery, solid handling, and failure frequency - repair cost and operational expense and initial lift cost and required infrastructure. The output from the type of

curve/production forecast, combined with well performance modeling was used to determine future well and reservoir performance. Formation was grouped into various categories based on reservoir characteristics and fluid properties

The results showed cases of lift type selection for various types of unconventional formation. Actual well performance and lease performance results are also presented.

The managed production (drawdown) period has a major deciding factor on the artificial lift selection strategy. Combination of traditional artificial lift selection processes with several other model output to create artificial lift selection strategy for Permian Delaware basin unconventional formation is applicable in other unconventional basins

Introduction

The challenges of producing and lifting unconventional oil and gas economically has remained the most daunting phase of unconventional oil and gas development. Unconventional wells typically follow in a hyperbolic decline production curve pattern, with high decline rate between 40% and 80% in the first year. Slug flow, high free gas production, solids production (proppant, scale, and paraffin), horizontal wellbore geometry, and surface pad for multi-well in a cellar. This and other unique unconventional well problems are continuously pushing the limits of all our existing lift systems.

As the industry began developing unconventional oil and gas, the only options available to lift were the traditional artificial lift systems that were developed for conventional oil and gas applications, which were adopted and applied to unconventional wells without major changes in both technology and application improvement in mitigating the challenging unconventional oil and gas environment. The result was obvious: lift systems that had performed efficiently in various environments and well conditions for decades struggled to work well in this new unconventional application. As an industry, lessons learnt, though at significant cost! We are now better positioned to apply artificial lift system efficiently in the unconventional arena. This situation described above is not just unique to one specific artificial lift system; but it cuts across all lift types. The effect of inefficient artificial lift selection strategy and, improper application on field profitability, varies from one lift system to another. For example: The high cost of failure repair; due to rig requirement to pull tubing in an ESP system, amplified the inefficiency of the ESP performance in unconventional applications over other lift systems in a high failure frequency situation.

This paper presents some of the lessons learnt; also a holistic approach to Artificial Lift selection strategy, process requirement to maximize unconventional oil and gas assets value is discussed. The presentation includes a case study of Permian Delaware basin unconventional formations. The lift evaluation process which includes, a combination of reservoir fluid properties, and well performance impact was used to analyze the effect of various artificial lift selection options on the life of well value.

The paper described, not only the three distinct and important periods of unconventional well life, but also effective artificial lift systems applicable during each period. An Artificial lift system is phased over the life of the well based on current and expected production rate requirement and lift method capability. The lift systems were further evaluated based on several criteria through elimination and selection techniques.

The author recommended series of artificial lift strategy for various types of unconventional formation in the Permian Delaware basin based on lesson learnt, and all of the evaluation work described in this paper. While the study area in this paper is focused on Permian Delaware basin, the recommended artificial lift selection strategy presented, is applicable in many other unconventional basins. A major conclusion in this paper is that the management, and control of volatile oil production during the managed (drawdown) period, has a major deciding factor on the artificial lift selection strategy and the economic value of the life of the unconventional well.

Permian Delaware Basin

The Permian Delaware basin is one of the most prolific unconventional oil and gas basins in the US. **Fig.1** – shows Eddy and Lea Counties of the Delaware basin, as the leading oil producing counties in the Permian. The positive trend of drilling highly productive wells was the major reason; the basin demonstrated a high level of resilience to the 2014 fall in oil and gas prices.

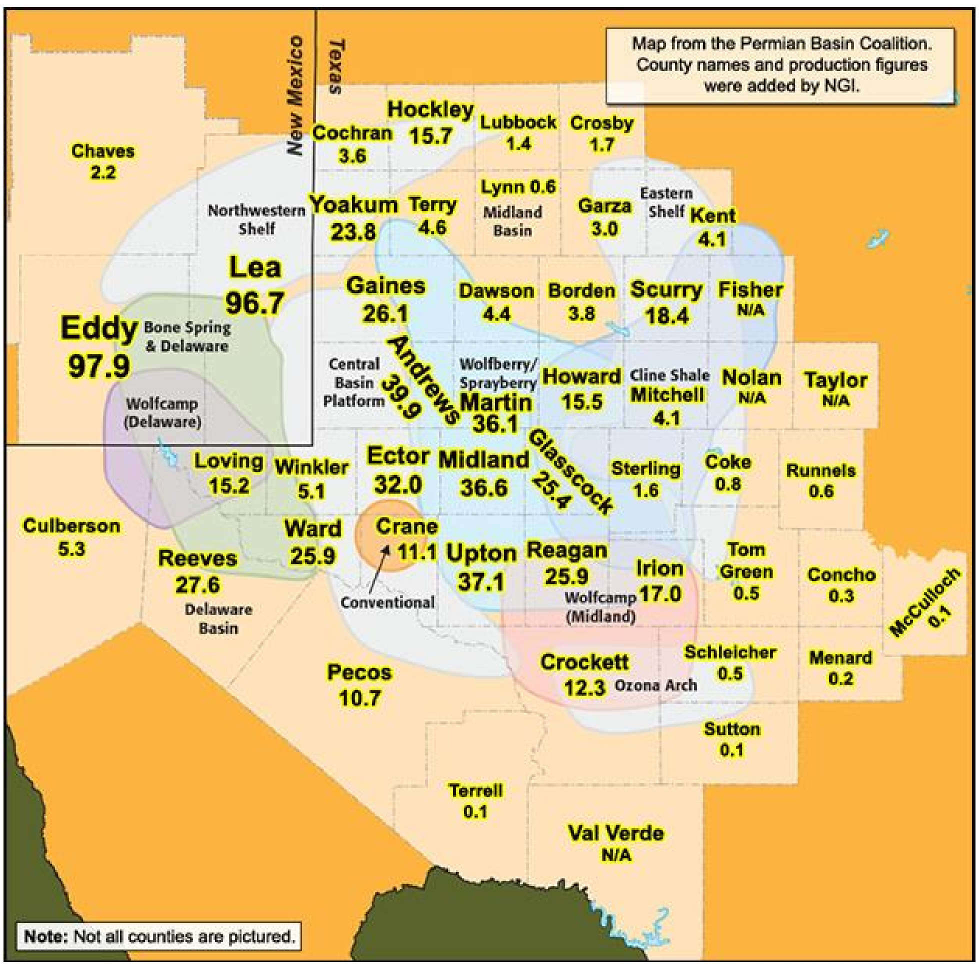


Fig. 1: RRC Reported Estimated Cumulative Crude Oil Production by County (Jan 2004-Jul 2015) – Courtesy NGI

The Delaware Basin is a multi-stacked play prospect; that contains several productive zones (see **Fig.2&3** below). Hydrocarbon producing zone thickness as high as 1800 feet are common in the basin; comparing this to the Bakken Shale highs of 120 feet in thickness, and Eagle Ford Shale formations of 300 feet thick (NGI'Shale Daily, 2016); the Delaware basin is no doubt a world class oil and gas basin.

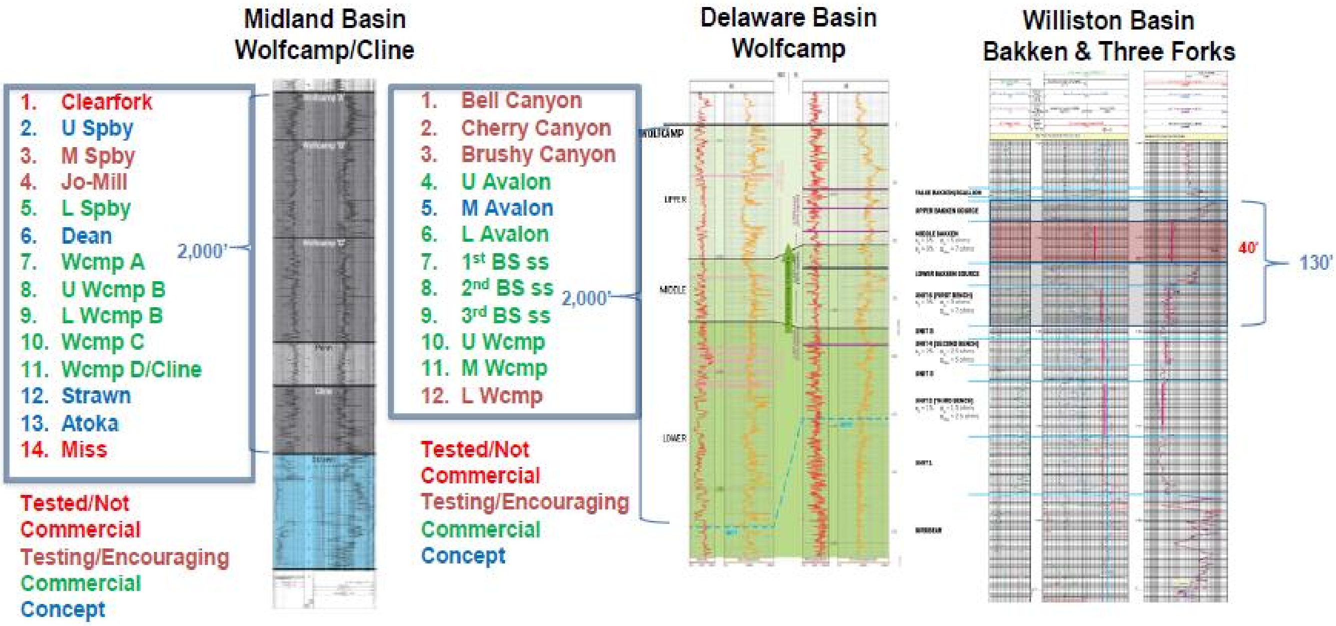


Fig. 2: Delaware Basin Wolfcamp dwarfed Williston Basin Bakken & Three Forks

It is extremely important to note that each of these hydrocarbon producing zones in **Fig.2** has distinct and unique rock and fluid properties. Hydrocarbon zones with similar depositional origin, may also exhibit some differences from one region of the basin to another region. Non-recognition or appreciation of these changes and complexity has resulted in poor artificial lift selection and performance in some of the unconventional producing zones in the Delaware basin. Incorporating the full understanding of these rocks and fluid phase behaviors into the artificial lift strategy is the bedrock to successfully improve the lift system performance in the Delaware basin

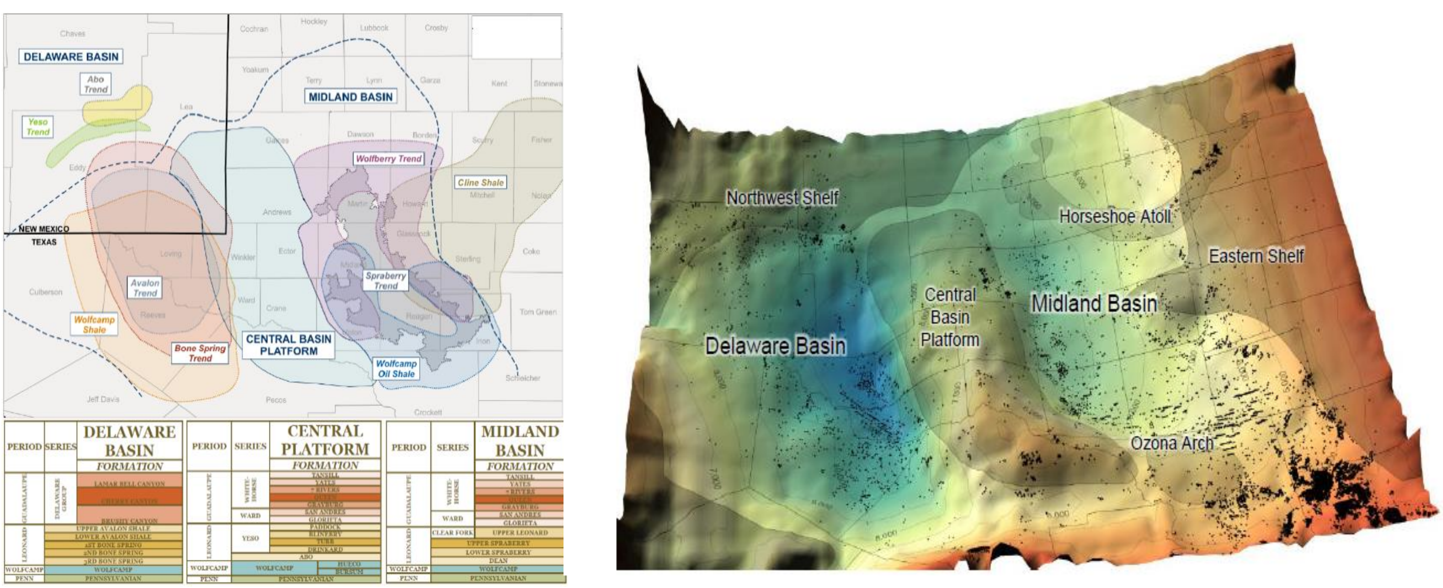


Fig.3: The Permian Basin

Artificial Lift Systems in Permian Delaware Basin

ESP

The industrial reward structure that was based heavily on initial production (IP) rate, and first-90/180days; cumulative production coupled with record high oil prices made ESP system the most favorable lift system in the basin. ESP system with its capability to drawdown the well and deliver record production rates became the first lift system installed in wells after the initial well completion.

Frac sand and gas handling became the primary root cause of failure for most ESP failures. The 3-6 months runlife was an acceptable failure frequency in the basin. The industry responded with improved technology and application to mitigate both sand and high gas production problems, which resulted in some measurable success.

Remarkable improvement on ESP for unconventional includes the following:

- Inverted Shroud Application
- Gas Separator and Handler Design Improvement
- Tamdem Gas Separator
- Multi-Tapered Pumps
- Sand Guard
- Coated Stages
- AR Sleeves
- VSD Operation Mode Improvement – Gassy/Gas Lock Mode & Current (I-Limit)

However, the biggest value has been obtained through proper lift selection strategy of keeping ESP in mainly low GLR wells only.

Rod & Beam Pump

It is the Greater Permian basin's most popular artificial lift system. The low Normal Lease Operating Expense (NLOE) due to low failure cost, and low failure frequency as shown in **Table 1**; had led to several beam pump installations in the Delaware Basin.

The common practice in the Delaware Basin is to install Beam Pump through a lift conversion from the other form of artificial lift that was initially installed as part of well completion. Intermittent beam pumping option is becoming a common practice among some operators seeking to save money by installing Beam Pump from the beginning of the well life to the end of the well life.

While beam pump cannot handle significant amounts of free gas (such as GLR >2000) successfully as other lift systems like PCP and ESP. The impact of gas and solid related failure on NLOE is not as significant as the other forms of lift systems.

Capability to produce high rate at depth, and depth limitations based on structural load of the system remain the biggest constraints in the Beam Pump application in the Delaware Basin.

Potential Savings from ESP to R&B
These LOE costs do NOT include water disposal costs!

	PLU	PLU-JV	JRU	BEU
ESP				
Total NLOE w/o AS&FE	$11,097	$11,425	$10,562	$15,228
AFE'd & Maint. Expense (WS AFE)	$6,296	$16,952	$9,049	$13,244
Total LOE w/o AS&FE	$17,393	$28,377	$19,611	$28,472
R&B				
Total NLOE w/o AS&FE	$3,441	$5,837	$3,358	$2,945
AFE'd & Maint. Expense (WS AFE)	$1,941	$3,265	$1,000	$1,000
Total LOE w/o AS&FE	$5,382	$9,102	$4,358	$3,945
ESP Premium	**$12,011**	**$19,275**	**$15,253**	**$24,527**
Electrical Cost Savings	$1,000	$1,000	$1,000	$1,000
Total ESP Premium	**$13,011**	**$20,275**	**$16,253**	**$25,527**

Table 1: Rod and Beam Pump NLOE Comparison

Installation of big pumping units (such as the “1280 unit” and, “912 units”); long stroke (>20feet) hydraulic pumping units, fiberglass rod are some of the methods of extending the beam pump production rate envelop in the Delaware Basin.

Gas mitigation through long stroke unit operations, Variable Frequency Drives (VFD) with variable upstroke and downstroke control mechanism, varied types of gas anchors and gas separators are common practices in the basin.

Note that gas interference is unavoidable especially in horizontal unconventional wells. However, fluid pounding should be avoided at all costs.

Gas Lift

Gas Lift is now the fastest growing lift systems in the basin. This is mainly due to the drive for lower OPEX/LOE and better understanding of the producing formation/fluid behavior.

Initial resentment about Gas Lift application was driven by lack of Gas Lift experience in the basin. Additional concern about the capability of Gas Lift to provide desired drawdown and production rate; coupled with high initial cost of infrastructure, made Gas Lift the least favorable option during the earlier field development in the basin.

Bottom hole pressure <650 psi has been achieved in test conditions with reservoir pressure (approx. 2000psi).

Perhaps! the recent application of Gas Lift Assisted Plunger/Plunger Assisted Gas Lift had expanded the Gas Lift application window in the basin.

Jet Pump

Jet Pump was introduced into the basin as a frac sand clean out pump before the installation of a longer artificial lift system. Jet pump capability to handle solid, flexible production rates, ease and “no to extremely low cost of replacement” had made it an attractive lift option for many operators in the basin. As may be expected, the low OPEX and low commodity price environment is expanding the use of jet pumps, as a longer period lift choice in the basin.

The biggest setback for jet pump is its well drawdown capability due to its high Net Positive Suction Head requirement (NPSHr). For our test application, Bottom hole pressure of 1200 psi was the lowest drawdown pressure attainable at the test conditions with a reservoir pressure (approx. 2500psi).

Costly environment spill was another major issue we experienced on our jet pump application field tests. The effect of gas on jet pump performance is another major concern in jet pump application. Although jet pumps do not gas lock like other “pumps”, the efficiency of the jet pump system erodes significantly at high gas volume fractions. This is the main reason why there had been great success for jet pumps in the undersaturated high reservoir pressure Wolfcamp wells in the Delaware Basin.

The current trend of using centrifugal horizontal surface pump with jet pump rather than the traditional duplex/triplex positive displacement pump will improve operational efficiency and assist in optimizing jet pump performance.

Plunger Lift

Plunger lift is not traditionally considered as a feasible option for high volume oil wells. Mainly because plunger lift depends entirely on the natural reservoir energy of the formation. Plunger lift is now becoming one of the most economical viable option for certain formations and certain period of the well life. We recently converted one of our Bone Spring well from natural flow to plunger lift.

High GLR Bone Spring formation and over pressured Wolf Camp had most success on plunger lift. The completion strategy of smaller size liner (such as 4-1/2”, 3-1/2”, and 2-7/8”) seems to be assisting plunger lift performance in the unconventional oil formation in the basin.

Artificial Lift Elimination and Selection

As it is well known, there is a wide range of artificial lift systems available for unconventional oil and gas application. The requirement to eliminate and select the best artificial lift method and strategy for the life of the well cannot be over-emphasized.

Yearly, the industry loses billions of dollars in both revenue loss and lift conversion or inefficient lift performance and failure expenses due mainly to improper artificial lift selections. The current major requirement to lower lifting cost for unconventional oil to compete favorably with conventional oil lifting cost is to renew focus on artificial lift selection in the basin. Several important factors need to be considered in artificial lift elimination and selection process (Lea, Nickens, Wells, 2008); (Oyewole, Lea, 2008).

This paper groups all major factors to consider in artificial lift elimination and selection into four main categories for better understanding (see **Fig. 4**):

1) Technical considerations
2) Surface and infrastructure considerations
3) Drilling/reservoir/G&G considerations
4) Economic considerations

This section will provide cases that considered some of these factors to eliminate and select the most effective lift systems with the main focus on maximizing the asset value.

Note: Technical, Surface and infrastructure, Drilling/reservoir/G&G considerations are important input into the Economic considerations. The Economic consideration is based on the Operators objectives, driven by its business plans and model.

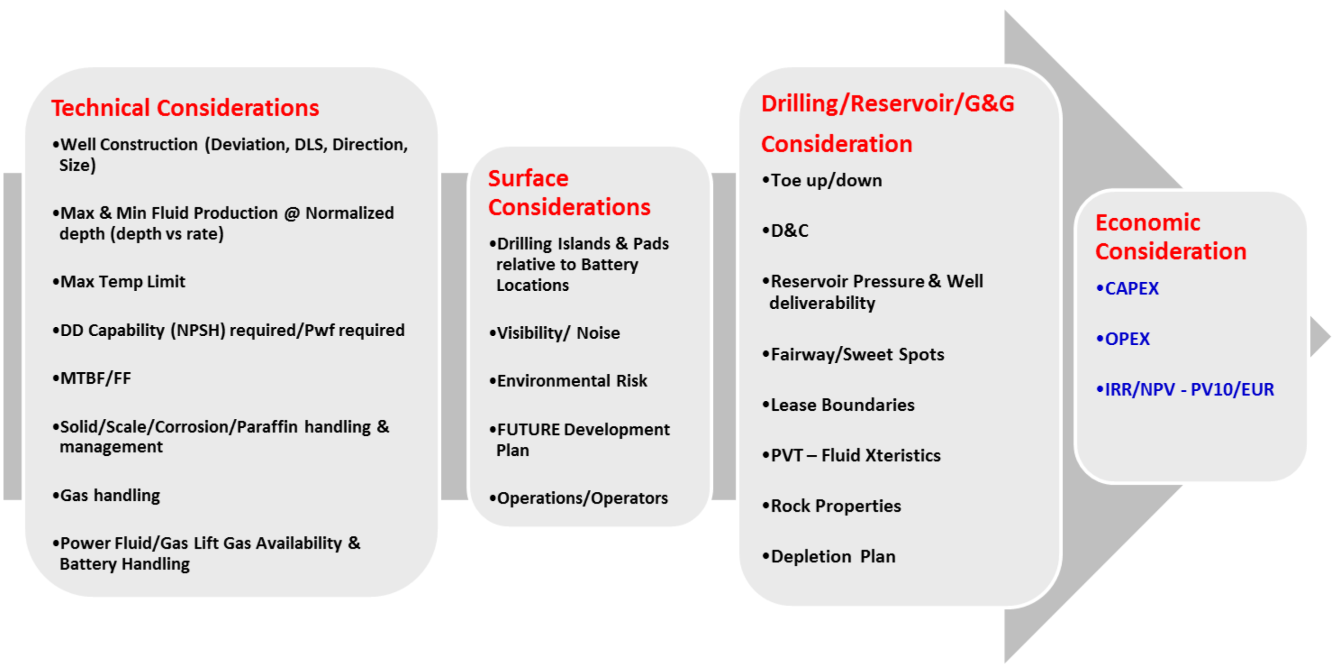


Fig. 4: Artificial Lift Elimination and Selection Consideration Categories

Reservoir Characteristics & Fluid Phase Behavior

The lack of detailed reservoir characteristics and fluid phase behavior input in many artificial lift strategies is unexplainable. Perhaps! This might be due to lack of understanding its value in artificial lift selection strategy. It may also be due to lack of data. This paper demonstrates how reservoir and fluid properties provides a deciding input into the artificial lift selection strategy.

In the Delaware basin, the geological depositional environment, reservoir and fluid properties, not only varies by formation with depth **(Fig.2)**; strong regional variation is observed with distance in the same formation. See **Fig. 5** below, it highlighted the GOR variation in the basin. This provided additional layer of complexity to defining artificial lift strategy to maximize the asset value. Definitely, this is the main reason why – one artificial lift type strategy, is not always an effective strategy.

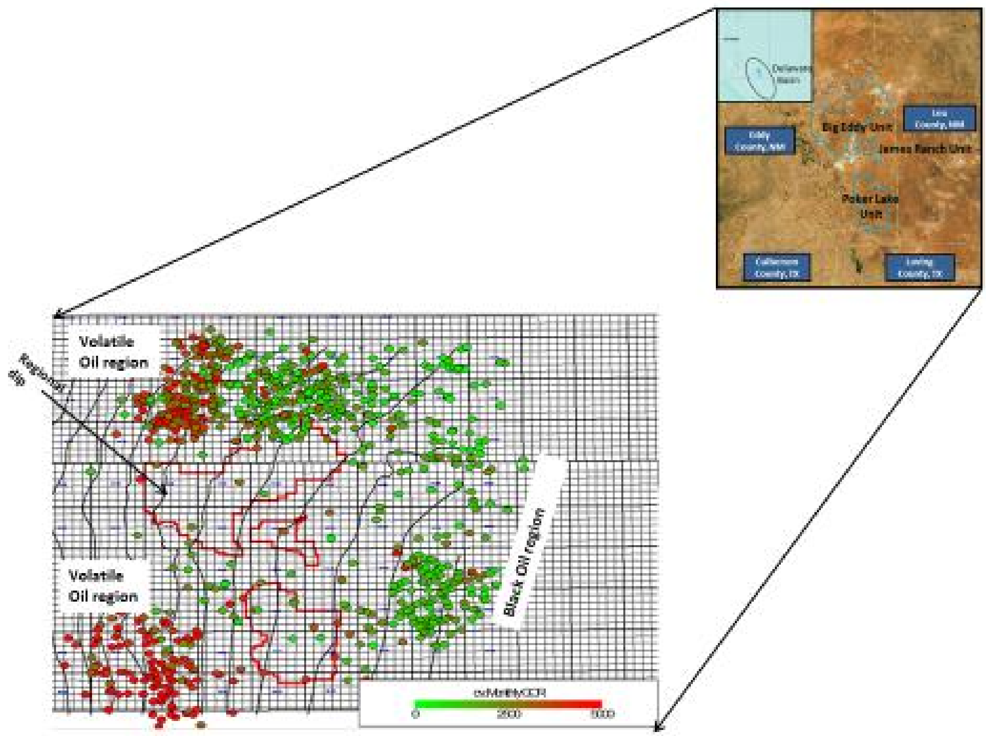


Fig.5: 180 Day GOR's Plot - 2nd Bone Spring Sand Horizontal Wells in Eddy County, Delaware Basin

The author presented "3-well evaluation" to artificial lift selection strategy that is driven mainly by fluid properties. This is named **Well1, Well 2 and Well 3** for simplicity. **Table 2** shows pertinent PVT data of the wells. While **Well 1** and **Well 2** are completed in the same 2nd Bone Spring Sand, the reservoir fluid type and properties varies distinctively. **Well 3** that was completed in the 1st Bone Spring Shale (few miles from **Well 2**) has the **highest shrinkage factor(Bo)**. No doubt, this invariably affects the lift selection and performance in the well.

	Well 1 2ND BSPG SAND	Well 2 2ND BSPG SAND	Well 3 FBSSH
Reservoir Fluid-Type	**Under saturated Black Oil**	**Under saturated - Volatile Oil**	**Saturated Oil**
Reservoir Pressure (psig)	**3,950**	**5,580**	**4,476**
Bubble Point Pressure (psig)	**2,900**	**5,235**	**4,503**
Gravity of Separator Oil (API)	40.9°	48.0°	53.9°
Reservoir Temperature °F	132	143	136
TVD (ft)	8900	9850	8927
Solution GOR scf/bbl	912	1832	1975
Relative Oil Volume (Bo) RB/STB (R T&P)	1.48	2.24	2.49

Table 2: Reservoir Fluid Properties Comparison

Fig. 6, 7 & 8 show historical production trends and data for **Well 1, Well 2 and Well 3**. The initial ESP installation equipped with downhole sensor provided valuable Pump Intake Pressure (PIP) data. A plot of ESP PIP versus GOR provided a comprehensive understanding of the behavior of the phases at different PIP.

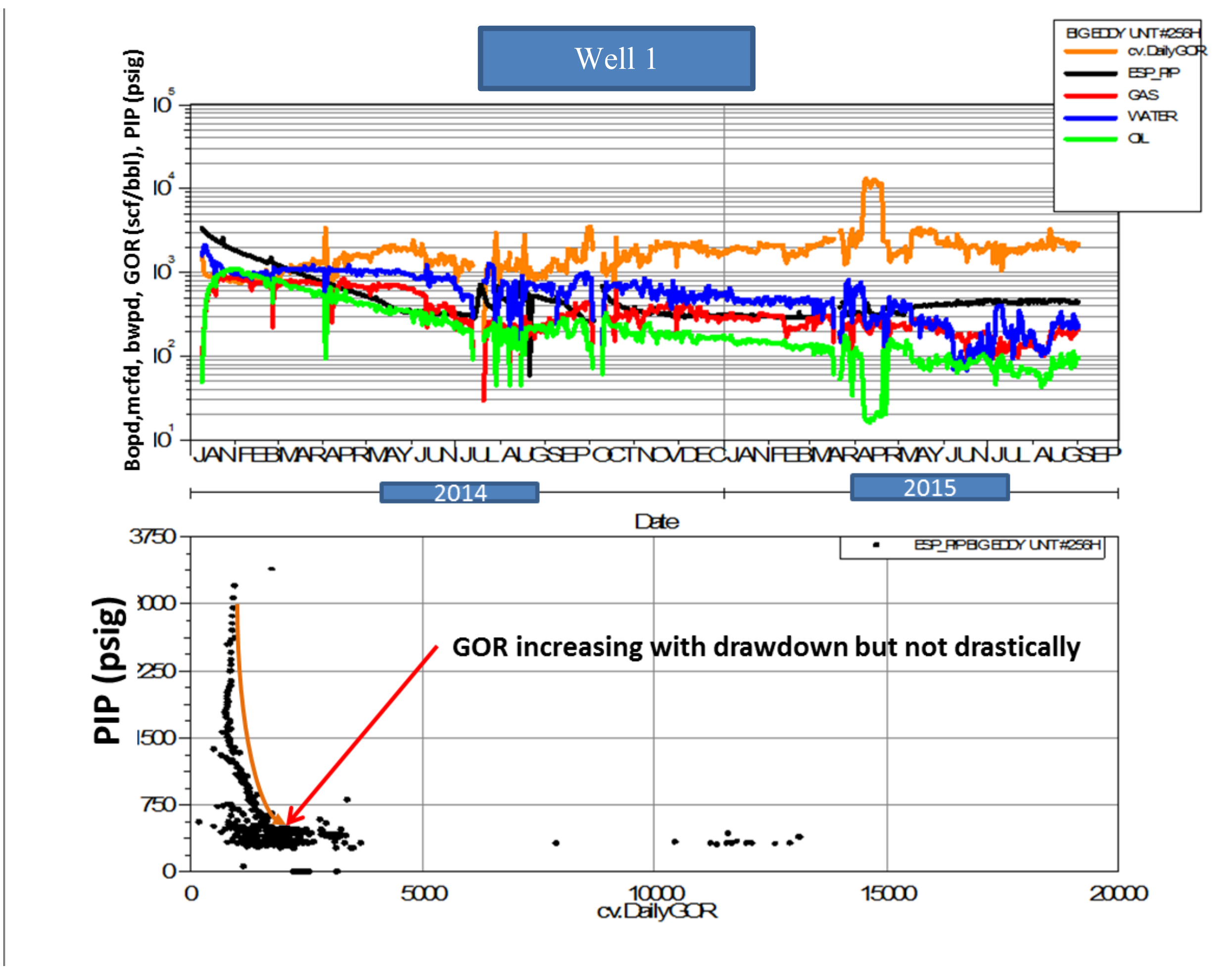


Fig. 6: Well 1 – Production trend and GOR vs PiP Plot

Based on reservoir fluid properties consideration:

The artificial lift strategy highly recommends pump (ESP - Early Life and Rod & Beam Pump-Late life) for **Well 1** and other unconventional wells with similar PVT and GOR behavior

Gas Lift is the recommended secondary choice if the oil cut and GLR remain high during the life of the well

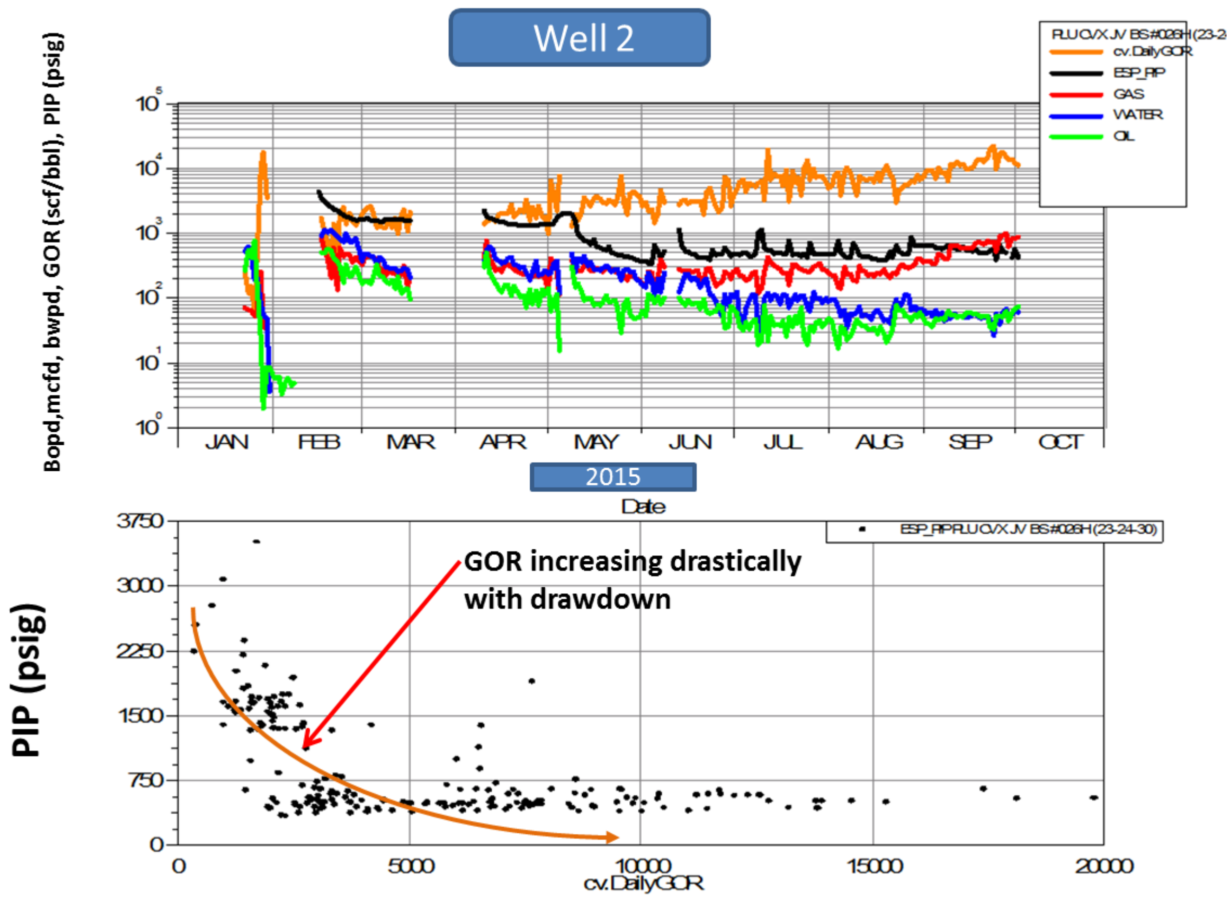


Fig. 7: Well 2 – Production trend and GOR vs PiP Plot

Based on reservoir fluid properties consideration:

The artificial lift strategy highly recommends Gas Lift for both Early life and Late life) for **Well 2**, and other unconventional wells with similar PVT and GOR behavior.

While the well can be pumped at a higher PIP, however, Gas Lift with Plunger assist will provide greater value at high oil cut. Rod & Beam Pump is a secondary choice at high water cut.

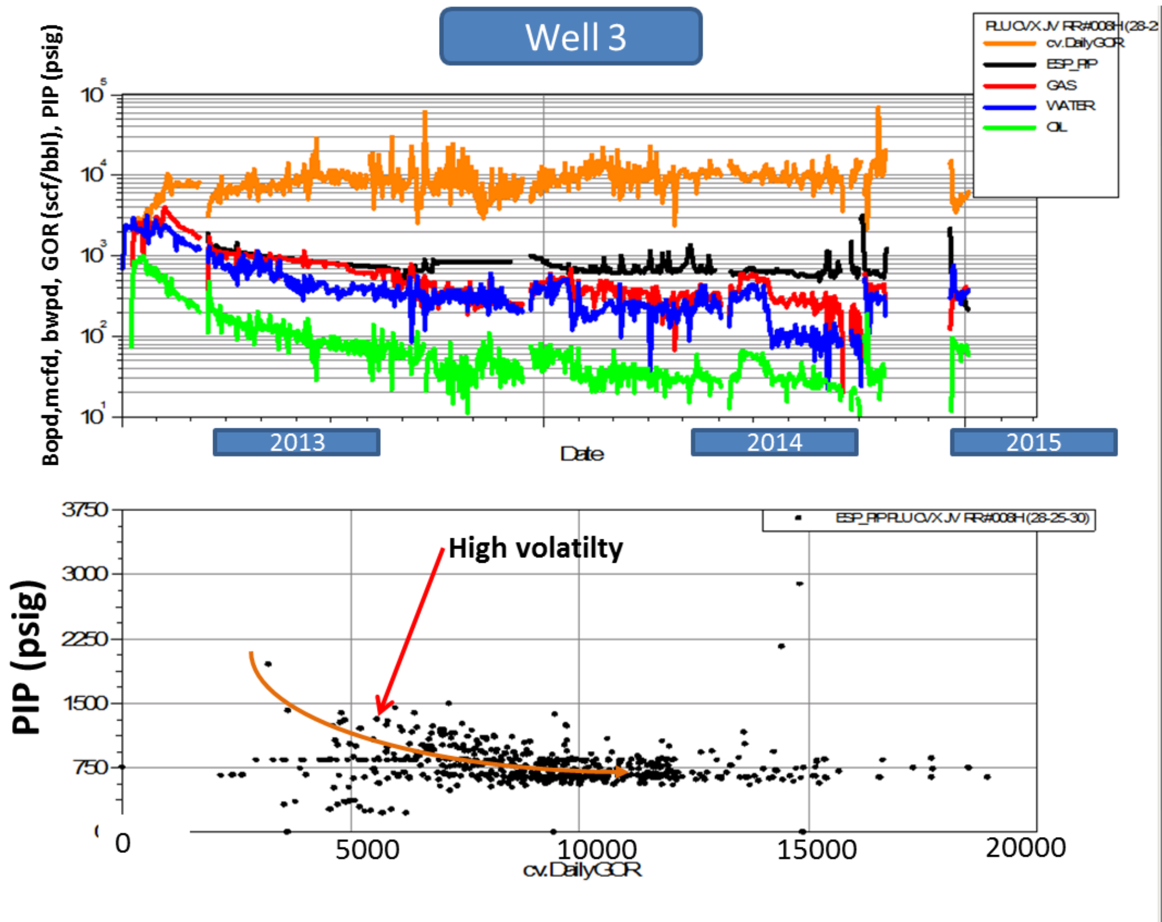


Fig. 8: Well 3 – Production trend and GOR vs PiP Plot

Based on reservoir fluid properties consideration:

The artificial lift strategy highly recommends Gas Lift for both Early life and Late life for Well 3. This will maximize the reservoir natural energy as the oil flashes significantly.

Gas Lift Application for Volatile Oil

Based on the well completion, volatile oil shale and tight sands can flow on both natural flow and high volume plunger lift for extended period (+/- 2 years). The only lift that is required to take the well to its economic limit is Gas Lift.

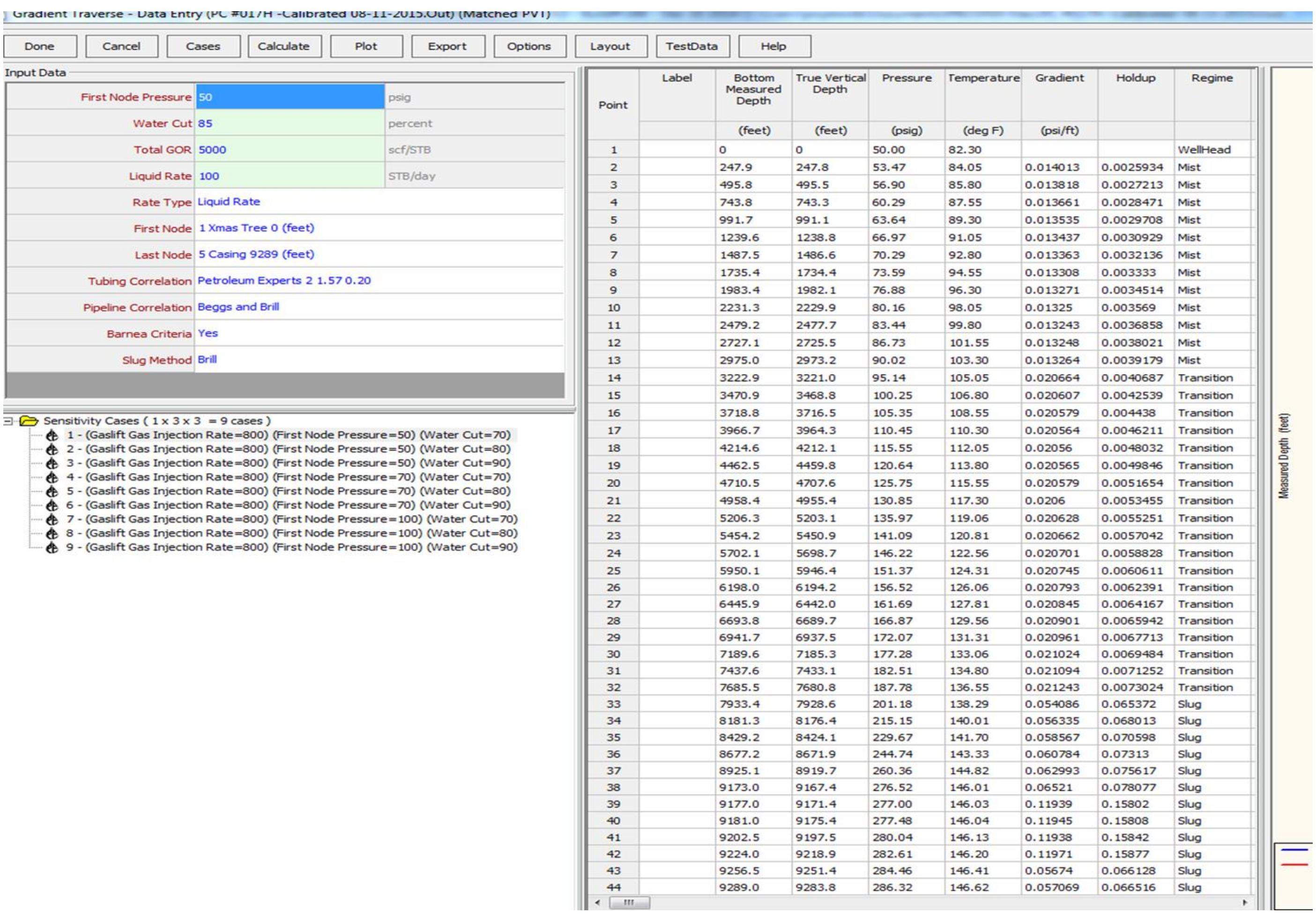
Current and Future Gas Lift Performance on a volatile oil shale was modeled, based on the output of a type curve similar to **Fig.12**. **Table 3**: is the output data for the Prosper nodal analysis that was performed with the **Solution GOR of 2454 scf/bbl: Total – 5000scf/bbl**.

	Year 3 (2015)	Year 15
Reservoir Pressure (psi)	**2400**	**1000**
BLPD	**150**	**100**
WC	**40**	**80**

Table 3: Model Input from Type Curve

Fig. 9 & 10 shows the model and sensitivity analysis result. Gas Lift was able to generate a sandface BHFP of 286psi, even at water cut as high as 85%. Also, tubing head pressure is the biggest factor in Gas Lift performance. The lowest tubing pressure of 50psi generated the lowest BHFP on the sensitivity plot in Fig.10.

Note: The common black oil outflow performance correlation could not model well performance accurately. Actual downhole data was used to calibrate and tune the model to account for volatile oil performance.



Point	Label	Bottom Measured Depth (feet)	True Vertical Depth (feet)	Pressure (psig)	Temperature (deg F)	Gradient (psi/ft)	Holdup	Regime
1		0	0	50.00	82.30			WellHead
2		247.9	247.8	53.47	84.05	0.014013	0.0025934	Mist
3		495.8	495.5	56.90	85.80	0.013818	0.0027213	Mist
4		743.8	743.3	60.29	87.55	0.013661	0.0028471	Mist
5		991.7	991.1	63.64	89.30	0.013535	0.0029708	Mist
6		1239.6	1238.8	66.97	91.05	0.013437	0.0030929	Mist
7		1487.5	1486.6	70.29	92.80	0.013363	0.0032136	Mist
8		1735.4	1734.4	73.59	94.55	0.013308	0.003333	Mist
9		1983.4	1982.1	76.88	96.30	0.013271	0.0034514	Mist
10		2231.3	2229.9	80.16	98.05	0.01325	0.003569	Mist
11		2479.2	2477.7	83.44	99.80	0.013243	0.0036858	Mist
12		2727.1	2725.5	86.73	101.55	0.013248	0.0038021	Mist
13		2975.0	2973.2	90.02	103.30	0.013264	0.0039179	Mist
14		3222.9	3221.0	95.14	105.05	0.020664	0.0040687	Transition
15		3470.9	3468.8	100.25	106.80	0.020607	0.0042539	Transition
16		3718.8	3716.5	105.35	108.55	0.020579	0.004438	Transition
17		3966.7	3964.3	110.45	110.30	0.020564	0.0046211	Transition
18		4214.6	4212.1	115.55	112.05	0.02056	0.0048032	Transition
19		4462.5	4459.8	120.64	113.80	0.020565	0.0049846	Transition
20		4710.5	4707.6	125.75	115.55	0.020579	0.0051654	Transition
21		4958.4	4955.4	130.85	117.30	0.0206	0.0053455	Transition
22		5206.3	5203.1	135.97	119.06	0.020628	0.0055251	Transition
23		5454.2	5450.9	141.09	120.81	0.020662	0.0057042	Transition
24		5702.1	5698.7	146.22	122.56	0.020701	0.0058828	Transition
25		5950.1	5946.4	151.37	124.31	0.020745	0.0060611	Transition
26		6198.0	6194.2	156.52	126.06	0.020793	0.0062391	Transition
27		6445.9	6442.0	161.69	127.81	0.020845	0.0064167	Transition
28		6693.8	6689.7	166.87	129.56	0.020901	0.0065942	Transition
29		6941.7	6937.5	172.07	131.31	0.020961	0.0067713	Transition
30		7189.6	7185.3	177.28	133.06	0.021024	0.0069484	Transition
31		7437.6	7433.1	182.51	134.80	0.021094	0.0071252	Transition
32		7685.5	7680.8	187.78	136.55	0.021243	0.0073024	Transition
33		7933.4	7928.6	201.18	138.29	0.054086	0.065372	Slug
34		8181.3	8176.4	215.15	140.01	0.056335	0.068013	Slug
35		8429.2	8424.1	229.67	141.70	0.058567	0.070598	Slug
36		8677.2	8671.9	244.74	143.33	0.060784	0.07313	Slug
37		8925.1	8919.7	260.36	144.82	0.062993	0.075617	Slug
38		9173.0	9167.4	276.52	146.01	0.06521	0.078077	Slug
39		9177.0	9171.4	277.00	146.03	0.11939	0.15802	Slug
40		9181.0	9175.4	277.48	146.04	0.11945	0.15808	Slug
41		9202.5	9197.5	280.04	146.13	0.11938	0.15842	Slug
42		9224.0	9218.9	282.61	146.20	0.11971	0.15877	Slug
43		9256.5	9251.4	284.46	146.41	0.05674	0.066128	Slug
44		9289.0	9283.8	286.32	146.62	0.057069	0.066516	Slug

Fig. 9: Well Performance Model

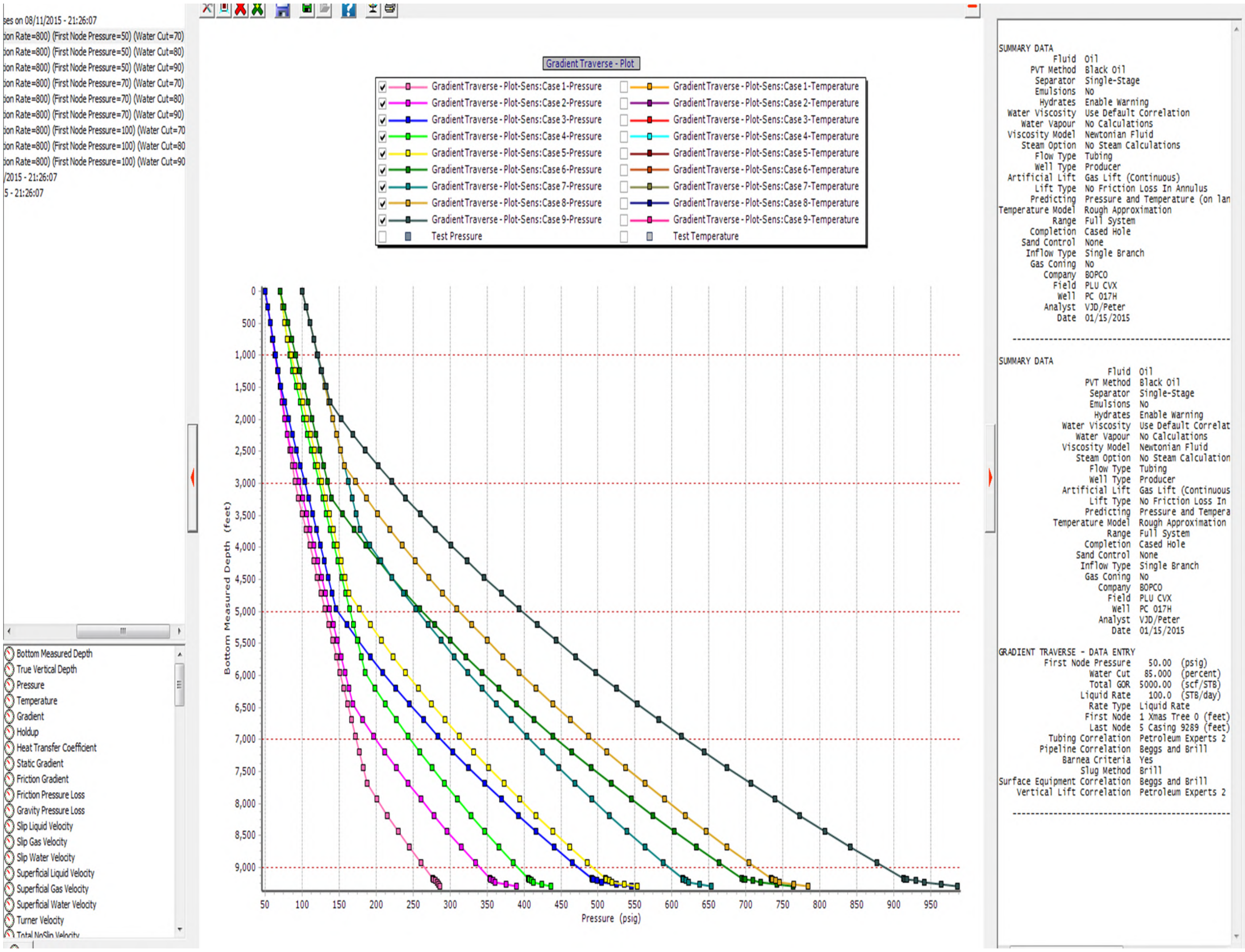


Fig. 10: Well Performance Sensitivity Plot

Depletion Period

As described in previous sections of this paper, maximum reservoir drawdown does not necessarily equate to maximum oil production. Free gas production increases significantly with BHFP reduction **(Fig.11)**. This results in reduction of liquid (oil) production. This invariably affects the asset EUR.

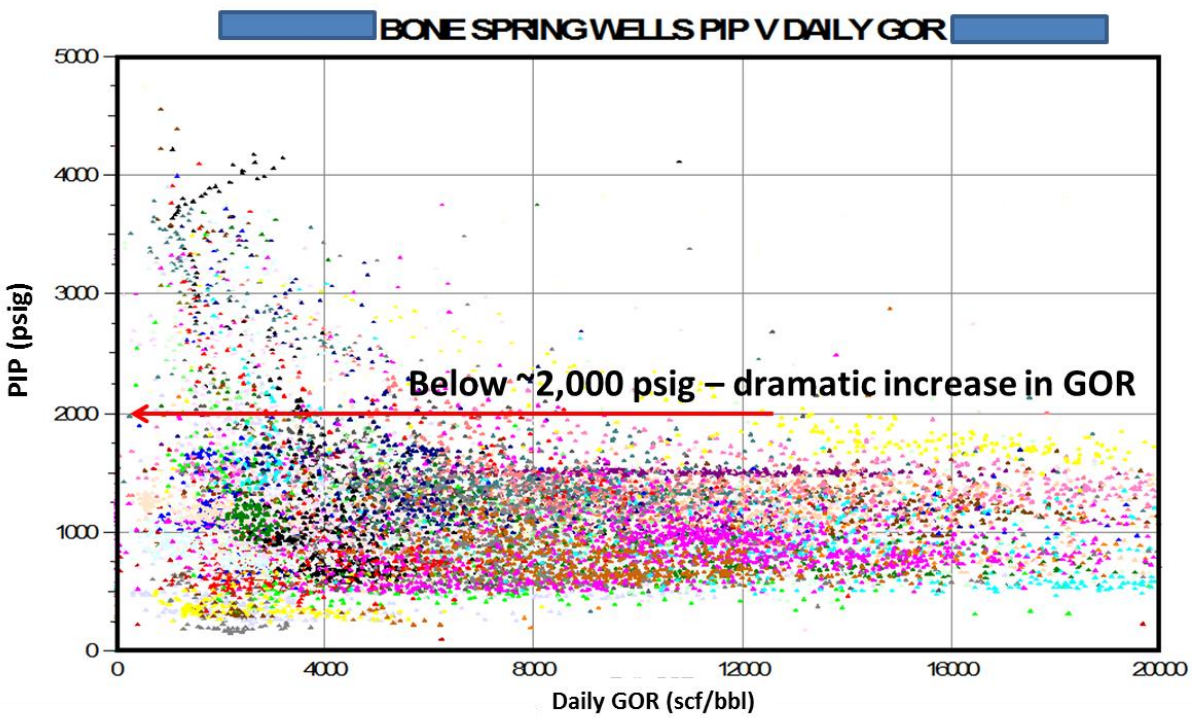


Fig. 11: GOR increases as BHFP reduces (Gas Damage)

The old way of thinking (conventional way) is production acceleration – produce all you can, as fast as you can afford; this will result in lower EUR and asset value.

Three distinct periods **(Fig.12)** were defined to describe for the volatile shale and tight sand oil well life:

1.) Managed Flow-Back
This is the period when we strive to avoid severe drawdown during flowback and load recovery that appears to impose damage to the proppant pack. Driven mainly by rock properties and proppant.

2.) Managed Production (Managed Drawdown)

This is the period when we strive to avoid severe drawdown during production to avoid gas damage. Large drawdown during the production phase, subjects the near wellbore to pressure drops that moves the near well bore region through the bubble point. Loss of reserves is a concern due to high GOR and loss of drive energy. By monitoring and controlling the BHFP, it minimizes the detrimental effects of gas damage

3.) Managed Depletion

This is the period when we strive to deplete the reservoir in order to maximize production. A “Post Managed Production Phase” when BHFP is low enough and there is no/low risk of gas damage in the reservoir.

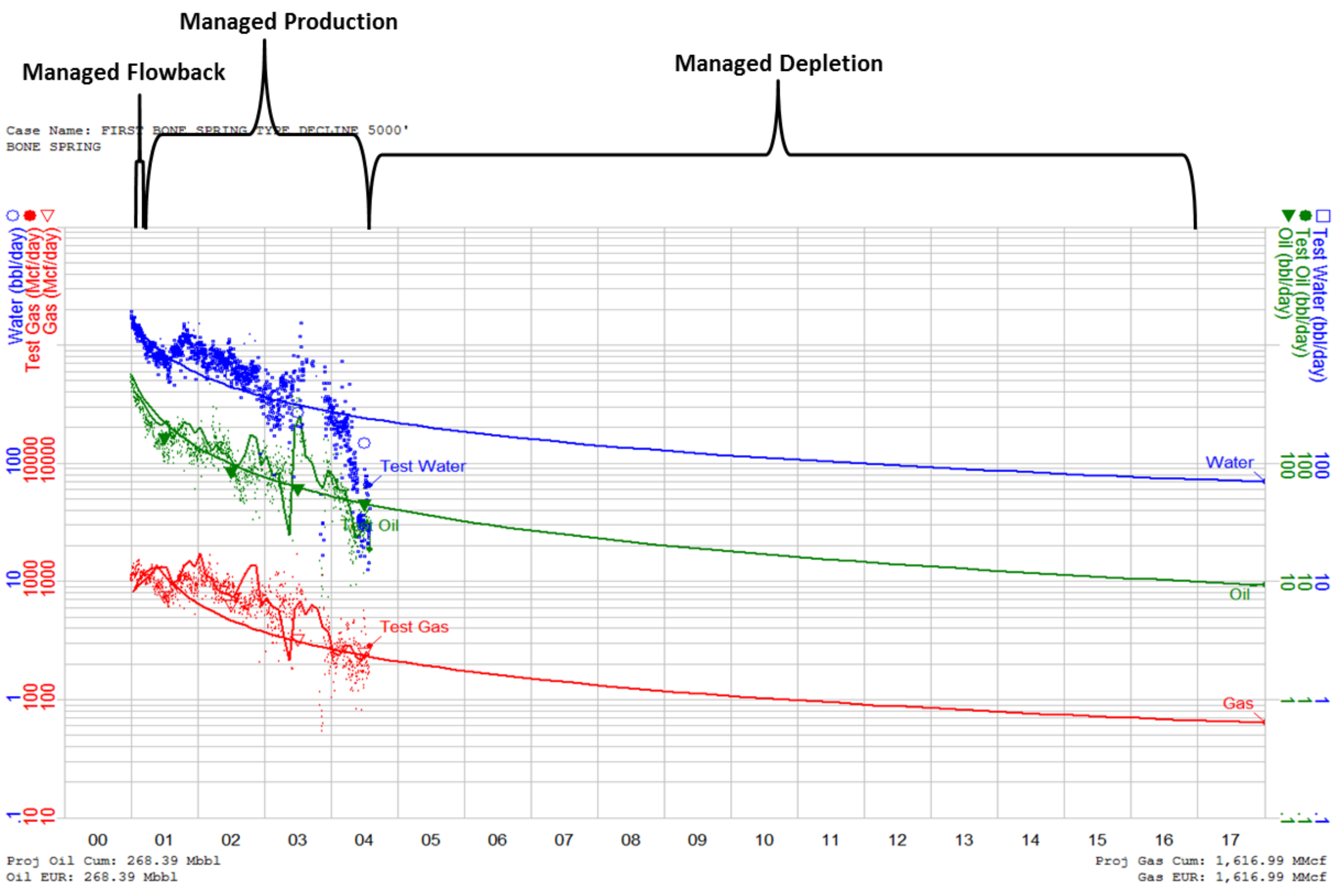


Fig. 12: Type Curve with Flow Period of Volatile Oil Well Life

Economic Consideration

This is a major factor in artificial lift strategy that is focused on maximizing unconventional oil and gas asset value. This is also driven by commodity price. Lowering Normal Lease Operating Expense (NLOE) is extremely important at low commodity price. At high oil prices, high ESP NLOE is driven mainly by incorrect Artificial lift selection strategy, can be easily masked.

Fig.13 shows Artificial Lift CAPEX and OPEX comparison chart.

It is important to note that ESP OPEX is now comparable to other forms of lift system in the basin based on the new Artificial Lift Strategy and vendor’s support on new contract.

Lift comparison	**Gas Lift**	**ESP**	**Rod and Beam**	**Jet Pump**
Artificial Lift Assembly	$145,387	$49,784	$150,210	$144,500
Work Over Cost	$19,280	$19,280	$19,280	$19,280
Surface equipment	$57,398	$18,555	$14,268	$24,072
Electrical surface equipment	$8,400	$9,940	$6,875	$9,940
Metering	$62,000	$0	$0	$0
Surface Electrical Labor	$6,000	$7,900	$6,000	$6,000
Artificial Lift Labor	$14,642	$4,776	$8,800	$7,620
Total capital cost	$313,107	$110,235	$205,433	$211,412
Incremental Capital cost over ESP	$202,872	$0	$95,198	$101,177
Monthly Rental ($/month)	$5,136	$6,200	$0	$0
Monthly Electric cost ($/month)	$2,850	$3,420	$1,900	$3,135
Failure frequency (Monthly cost)	$6,700	$25,000	13,500	$5,800
Expected TLOE- excluding SWD ($/month)	$14,686	$34,620	$15,400	$8,935
Cost Savings versus ESP ($/month)	$19,934	$0	$19,220	$25,685
Payout over ESP (months)	10.2	0	4.95	3.9

Fig.13: Lift comparison for economic consideration

Artificial Lift Strategy

All of the evaluation work above coupled with validating data from downhole sensors installed, on each artificial lift type, has definitely provided us valuable understanding of this massive hydrocarbon play. It has been a great insight into artificial lift performance in oil shale and tight sand formation.

It is important to recognize that as an industry, we are at the preliminary phase of developing and depleting unconventional oil. This means that we are on the learning curve and open to continuous learning and improvement.

The author recommended the following Artificial Lift Selection Strategy to enable unconventional oil and gas producers maximize their asset value.

………

Well Type 1 Description

- Undersaturated Reservoir
- Black oil type – PVT
- High Water Cut (>80%)
- Low Production Decline Rate
- High Liquid Volume Production (>500BLPD)
- Low GLR (<750 SCF/BBL)

Delaware Basin Example Formation – Brushy Canyon Delaware Formation (See Table 4) & Fig. 2).

Strategy 1 –ESP Only is highly recommended for the life of well.

Artificial Lift Conversion: No

ESP to Rod & Beam Pump Conversion might be required, if well performance does not meet expectation. However, this should be limited to avoid eroding the asset value.

………

Well Type 2 Description

- Undersaturated Reservoir
- Black oil type – PVT
- High Water Cut (>80%)
- High Production Decline Rate
- Low Liquid Volume Production (< 500BLPD)
- Low GLR (<750 SCF/BBL)

Delaware Basin Example Formation – Brushy Canyon Delaware Formation (Fig.2)

Strategy 2 – Rod & Beam Pump Only is highly recommended for the life of well. There is only Managed Flow Back and Managed Depletion Periods in the well life.

Intermittent Rod Pumping operations might be required during the earlier life while there is high reservoir pressure and high liquid volume production.

WELL_NAME	Oil (Bbls/d)	Water (Bbls/d)	Gas (MCFD)	Total Fluid (Bbls/d)	WC (%)	GOR (SCF/BBL)	GLR (SCF/BBL)
Delaware (Lower Brushy Canyon Well)	50	1,800	434	1,850	97	8,680	235
Delaware (Lower Brushy Canyon Well)	596	694	1200	1,290	54	2,013	930
Delaware (Lower Brushy Canyon Well)	151	1,202	676	1,353	89	4,477	500
Delaware (Lower Brushy Canyon Well)	158	923	413	1,081	85	2,614	382
Delaware (Lower Brushy Canyon Well)	219	1,483	636	1,702	87	2,904	374
Delaware (Lower Brushy Canyon Well)	143	1,101	450	1,244	89	3,147	362
Delaware (Lower Brushy Canyon Well)	91	1,028	729	1,119	92	8,011	651
Delaware (Lower Brushy Canyon Well)	165	1,098	608	1,263	87	3,685	481
Delaware (Lower Brushy Canyon Well)	106	1,001	964	1,107	90	9,094	871
Delaware (Lower Brushy Canyon Well)	247	1,007	854	1,254	80	3,457	681
Delaware (Lower Brushy Canyon Well)	130	1,349	527	1,479	91	4,054	356
Delaware (Lower Brushy Canyon Well)	35	955	365	990	96	10,429	369
Delaware (Lower Brushy Canyon Well)	83	737	579	820	90	6,976	706
Delaware (Lower Brushy Canyon Well)	59	1,127	380	1,186	95	6,441	320
Delaware (Lower Brushy Canyon Well)	56	929	411	985	94	7,339	417
Delaware (Lower Brushy Canyon Well)	49	749	615	798	94	12,551	771
Delaware (Lower Brushy Canyon Well)	63	797	551	860	93	8,746	641
Delaware (Lower Brushy Canyon Well)	16	605	297	621	97	18,563	478
Delaware (Lower Brushy Canyon Well)	121	790	378	911	87	3,124	415
Delaware (Lower Brushy Canyon Well)	46	691	42	737	94	913	57

Table 4: Delaware Lower Brushy Canyon Wells Sample

Well Type 3 Description

- Undersaturated Reservoir
- Black oil type – PVT
- High Reservoir Pressure
- Deep
- Low GLR (<750 SCF/BBL)

Delaware Basin Example Formation – Wolfcamp, 3rd Bone Spring, WolfBone (Fig.2)

Strategy 3 – Jet Pump is highly recommended for the early life of well.

Artificial Lift Conversion: Jet Pump to Rod & Beam Pump
Late Life conversion is required to improve EUR and maximize the asset, at low reservoir pressure

....
Well Type 4 Description

- Saturated Reservoir
- **Volatile oil type – PVT**
- High Water Cut (>80%)
- High Production Decline Rate
- Low Liquid Volume Production (< 500BLPD)
- Low GLR (<750 SCF/BBL)

Delaware Basin Example Formation – Avalon Shale, Bone Spring Shales, Bone Spring Sands, Wolfcamp, WolfBone (Fig. 2)

Strategy 4 – Rod & Beam Pump Only is highly recommended for the life of well. From Managed Flow Back to Managed Depletion Periods in the well life.

Artificial Lift Conversion: NO

Intermittent Rod Pumping operations might be required during the earlier life while there is high reservoir pressure and high liquid volume production.

....
Well Type 5 Description

- Undersaturated/Saturated Reservoir
- **Volatile oil type – PVT**
- Low Water Cut (< 80%)
- High Production Decline Rate
- Low Liquid Volume Production (< 500BLPD)
- High GLR (>1000 SCF/BBL)
- **High Gas Production (near or above tubing critical flow rate)**

Delaware Basin Example Formation – Avalon Shale, Bone Spring Shales, Bone Spring Sands, Wolfcamp, WolfBone (See Table 5)

Strategy 5 – Plunger Lift and Gas Lift Only from Managed Flow Back to Managed Depletion Periods in the well life.

Operation variation will include Plunger Lift, Plunger Assist Gas Lift/Gas Lift Assist Plunger during the well life. Unconventional Plunger type (Bypass or Ball & Sleeve) is required at earl life. Intermittent Gas Lift & Conventional Plunger is required at late life at low reservoir pressure

Artificial Lift Conversion: NO

WELL_NAME	Oil (Bbls/d)	Water (Bbls/d)	Gas (MCFD)	Total Fluid (Bbls/d)	WC (%)	GOR (SCF/bbl)	GLR (SCF/bbl)
Bone Spring (Volatile Oil Shale and Sand Well)	10	15	300	25	60	30,000	12,000
Bone Spring (Volatile Oil Shale and Sand Well)	30	47	350	77	61	11,667	4,545
Bone Spring (Volatile Oil Shale and Sand Well)	20	55	300	75	73	15,000	4,000
Bone Spring (Volatile Oil Shale and Sand Well)	68	242	1,000	310	78	14,706	3,226
Bone Spring (Volatile Oil Shale and Sand Well)	15	66	200	81	81	13,333	2,469
Bone Spring (Volatile Oil Shale and Sand Well)	100	200	713	300	67	7,130	2,377
Bone Spring (Volatile Oil Shale and Sand Well)	20	110	300	130	85	15,000	2,308
Bone Spring (Volatile Oil Shale and Sand Well)	30	133	360	163	82	12,000	2,209
Bone Spring (Volatile Oil Shale and Sand Well)	10	61	150	71	86	15,000	2,113
Bone Spring (Volatile Oil Shale and Sand Well)	57	522	1,142	579	90	20,035	1,972
Bone Spring (Volatile Oil Shale and Sand Well)	120	400	900	520	77	7,500	1,731
Bone Spring (Volatile Oil Shale and Sand Well)	44	180	360	224	80	8,182	1,607
Bone Spring (Volatile Oil Shale and Sand Well)	80	130	327	210	62	4,088	1,557
Bone Spring (Volatile Oil Shale and Sand Well)	33	393	578	426	92	17,515	1,357
Bone Spring (Volatile Oil Shale and Sand Well)	65	99	221	164	60	3,400	1,348
Bone Spring (Volatile Oil Shale and Sand Well)	119	157	371	276	57	3,118	1,344
Bone Spring (Volatile Oil Shale and Sand Well)	226	160	512	386	41	2,265	1,326
Bone Spring (Volatile Oil Shale and Sand Well)	33	73	125	106	69	3,788	1,179
Bone Spring (Volatile Oil Shale and Sand Well)	200	341	600	541	63	3,000	1,109
Bone Spring (Volatile Oil Shale and Sand Well)	20	162	200	182	89	10,000	1,099

Table 5: Bone Spring (Volatile Oil -Shale and Tight Sand) Wells Sample

Conclusion

This paper presented artificial lift selection strategy that is required to maximize unconventional oil and gas assets value using the prolific, but varied formation of the Permian Delaware Basin.

Traditional science, where maximum drawdown always equate to maximum production is no longer true for all types of formation. This does have a profound and direct impact on Artificial Lift Selection Strategy.

EUR is now path dependence in volatile oil production

No doubt, the management, and control of volatile oil production during the managed (drawdown) period, has a major deciding factor on the artificial lift selection strategy and the economic value of the life of the unconventional well.

Acknowledgement

The author express sincere appreciation to BOPCO L.P. (a private owned oil and gas operator with one of the largest acreage in the Permain Delaware basin) Management for the opportunity and their support.

The author also thanks the Reservoir Engineering and Operations Team for providing several materials in this work that eventually enable us to develop the appropriate Artificial Lift Strategy.

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Oyewole, P. O., and Lea, J. F. 2008. Artificial lift selection strategy for the life of a gas well with some liquid production. Presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado, 21-24 September. http://dx.doi.org/10.2118/115950-MS

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EXHIBIT G

UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

	:	
In Re:	:	
	:	Civil Action No.
ALTA MESA RESOURCES, INC.,	:	
SECURITIES LITIGATION	:	4:19-CV-00957
	:	
	:	

VIDEO-RECORDED ORAL DEPOSITION OF

Expert Witness

TAYLOR J. KIRKLAND

November 15, 2023
9:14 a.m.

4550 Travis Street
Dallas, Texas 75205

Stenographically Reported by:
MAYLEEN AHMED, RMR, CRR, CRC, TX-CSR #9428
Job No.: 6306381

VIDEO-RECORDED ORAL DEPOSITION OF TAYLOR J. KIRKLAND, an expert witness herein, and duly sworn, was taken at the offices of Kirkland & Ellis LLP, 4550 Travis Street, Dallas, Texas 75205 in the above-styled and numbered cause on November 15, 2023 from 9:14 a.m. to 6:47 p.m., before Mayleen Ahmed, Certified Shorthand Reporter in and for the State of Texas, reported by machine shorthand, pursuant to the Federal Rules of Civil Procedure.

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MIRANDA GLOVER, Videographer, Veritext
JESSICA REID, Concierge, Veritext

---o0o---

expert in this litigation?
A. Yes.
Q. So there's nothing that's not listed in your résumé that you believe is -- contributes to you potentially being an expert in this matter?
A. No.
MR. SHER: Objection to form.
Taylor, if you could just give me one second to object --
THE WITNESS: Sorry.
MR. SHER: -- before you --
BY MR. PETERS:
Q. And you provided -- did you provide any reports in this litigation?
A. Yes.
Q. How many reports have you provided in this litigation?
A. I had my own report and then a rebuttal report.
Q. So two?
A. Two.
Q. An opening and a rebuttal report?
A. Yes.
Q. Does your opening report contain any errors that you'd like to correct?

A. Not that I'm aware of.
Q. Does it contain any errors?
MR. SHER: Objection.
A. Not that I'm aware of.
Q. Did you take steps before you issued your opening report to confirm that it did not -- did not contain any errors?
MR. SHER: Objection.
A. I've reviewed it a number of times. I had a number of iterations of it. So yes.
Q. And does your rebuttal report contain any errors that you'd like to correct?
A. No.
Q. Are you offering any opinions in this litigation that are not contained in a report that you've issued in this litigation?
A. Not to this point.
Q. Do you have any expectation that you will provide an opinion in this litigation that you haven't provided already in a report in this litigation?
MR. SHER: Objection.
A. I don't expect to.
Q. Are you offering any opinions about the reasonableness of work performed to diligence the

business combination?

MR. SHER: Objection.

A. Work done by who?

Q. My question is: Are you providing any opinions in this litigation about work performed to due diligence the business combination --

MR. SHER: Objection.

Q. -- in this litigation?

A. Work performed by?

Q. By anyone.

MR. SHER: Objection.

A. I'm not sure I understand your question. One more time?

Q. Are you familiar with due diligence?

A. Yes.

Q. Okay. Are you providing any expert opinions in this litigation about due diligence performed in connection with the business combination?

MR. SHER: Objection.

A. I -- due diligence performed by who?

Q. Are you providing any expert opinion in this litigation about due diligence performed by or on behalf of Silver Run II?

MR. PETERS: Objection.

That in accordance with FRCP 30(e), before completion of the proceedings, review of the transcript was not requested and signature was reserved by the witness.

I further certify that I am neither counsel for, related to, nor employed by any of the parties in the action in which this proceeding was taken, and further that I am not financially or otherwise interested in the outcome of this action.

Certified to by me on this 18th day of November, 2023.

Mayleen Ahmed

/s/ MAYLEEN AHMED, RMR, CRR, CRC
Texas CSR No. 9428 - Exp 7/31/25
Washington CCR No. 3402 - Exp 12/29/23
Oregon CSR No. 17-0447 Exp 12/31/23
California CSR No. 14830 Exp 12/31/23
New York Realtime Certified Reporter
New York Notary Public

Veritext Legal Solutions
Registered Firm: 571

UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

IN RE ALTA MESA RESOURCES, INC. SECURITIES LITIGATION	Case No. 4:19-cv-00957 Judge George C. Hanks, Jr.

Errata To November 15, 2023 Deposition of Taylor Kirkland

Page / Line	Transcript Reads	Transcript Should Read	Reason For Change
4714	A line	align	mistranscribed
49/17	Sleek	Slick	mistranscribed
52/18	Corer	Core	mistranscribed
68/21	Invaris	Enverus	misspelled
128/5	Proved and	Proven	mistranscribed
212/17	1630	630	mistranscribed
214/24	Bollis	Bullis	misspelled
256/14	Weld-in sleeves	Well densities	mistranscribed
259/15	Dogmas	documents and	mistranscribed

Page / Line	Transcript Reads	Transcript Should Read	Reason For Change
263/2	Corridor	Core	mistranscribed
276/14	Hydrating	High grading	mistranscribed

12/29/23

(Date Signed)

Taylor Kirkland (Signature)

EXHIBIT H

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

IN RE:
ALTA MESA RESOURCES, INC. SECURITIES LITIGATION — Civil Action No. 4:19-cv-00957

____

ALYESKA MASTER FUND, L.P., ALYESKA MASTER FUND 2, L.P., AND ALYESKA MASTER FUND 3, L.P.,

Plaintiffs,

v. — Case No. 4:22-cv-01189

ALTA MESA RESOURCES, INC., f/k/a SILVER RUN ACQUISITION CORPORATION II; RIVERSTONE HOLDINGS, LLC; ARM ENERGY HOLDINGS, LLC; BAYOU CITY ENERGY MANAGEMENT, LLC; HPS INVESTMENT PARTNERS, LLC; JAMES T. HACKETT; HARLAN H. CHAPPELLE; WILLIAM GUTERMUTH; JEFFREY H. TEPPER; DIANA J. WALTERS; MICHAEL E. ELLIS; RONALD SMITH; DON DIMITRIEVICH; PIERRE F. LAPEYRE, JR.; DAVID M. LEUSCHEN; WILLIAM W. McMULLEN; DONALD SINCLAIR; STEPHEN COATS; and THOMAS J. WALKER,

Defendants.

REMOTE VIDEOTAPED DEPOSITION OF
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Deanna Amore - CRR, RPR, CSR - 084-003999

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Mariana Rojas, Entwistle, Paralegal
Belle Harris, Kirkland & Ellis, Litigation Associate

A. That's part of it, and then part of it is some of the email traffic internally where folks talked about they didn't really think it made sense, some of the employees.

Q. Let's take a look at paragraph 68.

Well, you say that it's crucial to balance a well's natural energy with the need for artificial lift. Did you assess that balance for any Alta Mesa well?

A. No.

Q. Would you agree that you should not install -- or an operator should not install an ESP -- actually, let me ask it differently.

Is it a good course of action to install an ESP after you have some data on how the well is doing?

A. Yes, you need some information on the inflow performance of the well to help you decide on your artificial lift.

Q. Are you aware that Alta Mesa waited until the spring of 2018 before it began to install ESPs?

A. That may be true. There's a little more to it than just the time because you have to establish -- you really need to establish an inflow performance curve which requires some specific

testing.

Q. Do you know whether or not Alta Mesa established an inflow performance curve on any of the wells it installed ESP on?

A. No, I don't know for sure. I just know that basically I'm basing that opinion on the -- predominantly on some email traffic I saw where folks that were involved in the process didn't really feel like it was working out as planned.

Q. Have you reviewed Mr. Fetkovich's rebuttal report?

A. Yes.

Q. And you testified earlier that you don't intend to offer any opinions in response to that rebuttal report?

A. Well, I said I wasn't asked to. Nobody has asked me to do that yet.

Q. Has -- do you currently intend to offer any opinions in response to his ESP economic analysis?

MR. BRODEUR: Objection.

THE WITNESS: Only if somebody asks me to do that.

BY MS. GRAGERT:

Q. Has anyone --

A. I'm sorry. Go ahead.
Q. No. I didn't mean to cut you off. You have these gaps in your speech that I think you're done, and I so apologize. Go ahead and finish your answer.
A. Yeah. No one has asked me to do a rebuttal yet.
Q. Have you ever been involved in a decision to install an ESP?
A. Yes.
Q. And how often have you been involved in that decision?
MR. BRODEUR: Objection.
THE WITNESS: Often in terms of like a -- so many months, or just a total number of times, I guess?
BY MS. GRAGERT:
Q. Total number of times.
A. I really don't recall. It's been a common technology in the oil patch for many, many years. I've worked on projects involving ESPs. So I can't really give you a number, but I'm familiar with ESPs.
Q. The typical run life of an ESP in certain basins is three to nine months?

A. It's going to depend on the amount of solids you produce, are you producing sand frac through the pump, do you have cavitation issues. So I think that would depend.
Q. Sir, take a look at paragraph 69 of your report. The second-to-last-sentence of that paragraph, you state "The typical run life of ESPs in certain basins is three to nine months."
Do you believe that --
A. I'm sorry. Go ahead.
Q. Do you believe that to be a true statement?
A. Hang on. Let me just make sure I got my report up here. I'm sorry. What page are we on?
Q. Page 24, paragraph 69, the second-to-last sentence.
A. Yeah, I believe I base that on this technical paper here.
Q. So the typical run life of ESPs in certain basins is three to nine months. Do you believe that is an accurate statement?
A. Yes.
Q. Do you believe that Alta Mesa installed ESPs for too long in their wells?
A. No.

C E R T I F I C A T E

I, DEANNA AMORE, a Shorthand Reporter and notary public, within and for the State of Illinois, County of DuPage, do hereby certify:

That HAROLD MCGOWEN, the witness whose examination is hereinbefore set forth, was first duly sworn by me and that this transcript of said testimony is a true record of the testimony given by said witness.

I further certify that I am not related to any of the parties to this action by blood or marriage, and that I am in no way interested in the outcome of this matter.

IN WITNESS WHEREOF, I have hereunto set my hand this 15th day of November 2023.

Deanna Amore

Deanna M. Amore, CRR, RPR, CSR

UNITED STATES DISTRICT COURT
SOUTHERN DISTRICT OF TEXAS
HOUSTON DIVISION

IN RE ALTA MESA RESOURCES, INC. SECURITIES LITIGATION	Case No. 4:19-cv-00957 Judge George C. Hanks, Jr.

Errata To November 13, 2023 Deposition of Harold E. McGowen III, PE

Page / Line	Transcript Reads	Transcript Should Read	Reason For Change
7/16	Harold McGowen III	Harold Edward McGowen III	Correction/Clarification
19/11	rehab	have	correction
24/3	it	unconventional pay	Clarification
43/7	said	sell	Correction
52/25	That's the optimal	The optimal	Grammar
55/8	change **and** the rate of change	change **in** the rate of change	Correction
55/9	, the velocity of a fluid particle or molecules is negligible	, **and** the velocity of a fluid particle or molecules, is negligible	Correction/Clarification

Page / Line	Transcript Reads	Transcript Should Read	Reason For Change
Page 56/13	and but	and	Correction/Clarification
Page 64/17	old	whole	Correction
Page 85/19	level	well	Correction
Page 86/3	doesn't	does	Correction
Page 114/16	approved	proved	Correction
Page 117	drawing	drainage	Correction
Page 121/11	fracturing	fractured	Correction
Page 122/25	to	in	Correction
Page 130/18	fraction	fracture	Correction
Page 133/6	tracing	tracer	Correction
Page 133/13	that form the wellbore	that extend from the wellbore	Correction/Clarification
Page 141/9	release	re-lease (as in lease again)	Correction
Page 141/18	build back	dial back	Correction/Clarification
Page 175/9	at	up	Correction/Clarification
Page 223/6	and new	and not new	Correction

Page / Line	Transcript Reads	Transcript Should Read	Reason For Change
Page 231/7	how I approach	how I would approach	Correction/Clarification
Page 232/19	the responsible well	the response of the well	Correction/Clarification
Page 238/24	long	far	Correction/grammar
Page 240/21	Share	Shale	Correction
Page 263/16	gas lifts	gas lift	Correction
Page 263/17	unusable	usable [life span]	Correction/Clarification
Page 265/10	you would run gas lift valves in the well of an ESP	you would not run gas lift valves in the well with an ESP	Correction/Clarification
Page 267/24	the power of	[that is required] to power	Correction/Grammar
Page 268/2	STACK piezos	stacked pays	Correction

Signature of Witness:

11/13/23

(Date Signed)

Harold E. McGowen III (Signature)